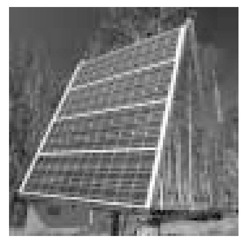
2001 Biennial Energy Report

Issues and Analyses for the Washington State Legislature

WASHINGTON STATE

Office of Trade & Economic Development

Martha Choe
Director

January 2001

2000 Biennial Energy Report

Issues and Analyses for the Washington State Legislature

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Energy Division
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January 2001

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TABLE OF CONTENTS

LIST OF FIGURES AND TABLES

Figures

Tables

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The Washington Office of Trade & Economic Development, Energy Division provides the Governor, Legislature, and other state and local government entities with information, analysis, and expert testimony to facilitate the inclusion of public interest criteria into state, regional, and national energy policy; develops, collects, and analyzes data on energy resources; develops and represents the state's energy interests in external policy forums; prepares the state to respond to petroleum and electricity supply shortages; and manages federal energy grants.

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• Petroleum	Arne Olson
• Publications, Reports	Karen Dunn
• Regulation	Elizabeth Klumpp
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The year 2000 saw energy return to front-page headlines. Increasing economic prosperity and tight crude oil supplies drove retail gasoline prices sharply higher. Disruptions in supply and early summer runoff coupled with a dysfunctional California electricity market meant that some industrial and institutional customers, and Washington utilities faced spot market prices of more than 70¢ per kilowatt hour of electricity during the summer. Natural gas prices nearly doubled. At the same time, the Northwest become concerned about the increasing risk of electricity disruptions because of declining energy conservation efforts and lack of new power plant construction. This 2001 Biennial Report to the Legislature provides background information on many of the major energy issues facing the state over the next two years.

Chapter 1 focuses on the electrical system in Washington and the Northwest. The chapter begins with the executive summary of the *Study of Western Power Market Prices Summer 2000,* an analysis by the Northwest Power Planning Council (NWPPC) of the factors that contributed to the major and largely unanticipated summer price run up. The Council's summary includes recommendations on how to lessen such major price disruptions through changes to market structure, risk management, and near-term demand management strategies.

The next section of Chapter 1 describes the proposed reconfiguration of the control and operation of the Northwest transmission grid including both a brief summary and a more detailed description of transmission planning over the last several years. This section is followed by an analysis of the numerous issues facing the Bonneville Power Administration including power contract subscription and pricing, fish and power issues, retention of regional electricity benefits, and related topics. We then discuss the increasingly important role that demand-side management can have in electricity peak load control and electricity supply and provide some examples of successful demand-side programs. The chapter concludes with a summary of the relative costs of meeting new electricity load through energy efficiency, natural gas-fired combined-cycle combustion turbines, wind turbines, and other commercial technologies. It also lists the new power facilities that were added or upgraded during the 1990's.

Petroleum is by far the largest share of the state's energy use accounting for 45% of our primary energy consumption. ***Chapter 2*** examines the recent history of and influences on the world crude oil market and the potential impacts on gasoline prices in Washington State. The chapter also discusses the supply effects of the 1999 Olympic pipeline explosion, and recent oil industry mergers.

Chapter 3 looks at natural gas pricing, the possible impacts of increasing natural gas demand, (especially by new electric generating facilities) on supply adequacy and price, and natural gas pipeline issues.

Chapter 4 describes the state's role in petroleum and electricity energy emergency planning and response. Both the 1999 Olympic Pipeline explosion in Bellingham and NWPPC's analysis of the increasing probability of winter electricity emergencies underscore the need to better understand energy emergencies, and our response to those emergencies.

Chapter 5 discusses the increasingly challenging issue of greenhouse gas emissions from fossil fuel combustion and use and the possible impacts of global climate change on the Pacific Northwest. It provides information on the state's greenhouse gas emissions, current research on climate impacts in the Northwest, and efforts to increase awareness and action on climate change in Washington and other states.

Finally, ***Chapter 6*** updates 24 key energy indicators that were first included in the 1999 Biennial Energy Report. Often the energy industry and policymakers find themselves responding to the events of the last few months or year without understanding the historical context of energy in Washington State's economy. These indicators are specifically designed to provide some of that broader, longer-term perspective on trends in state energy use and intensity, expenditures, prices, and the role of energy in the state's economy.

Appendix A and B contain the statutes governing the state energy office (Energy Division) and state energy emergency powers.

Note on State Energy Policy and the State Energy Strategy (SES)

Previous Biennial Reports (1995, 1997, and 1999), included information on the status of recommendations set forth in the 1993 State Energy Strategy (SES).[1] *The 2001 Biennial Report does not contain such a status account. While the SES continues to serve as "primary guidance for implementation of the state's energy policy,"*[2] *we believe that a detailed update in this report would be of limited value given that dramatic changes in the energy landscape since 1993 warrant a full examination and update of the SES. At the time of the writing of this report, the OTED Energy Division is working with the Governor's Office to set up a process to look at this new energy landscape and to revise and update the SES. We expect to begin this process after the end of the 2001 legislative session.*

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[1] Washington Energy Strategy Committee, *Washington State Energy Strategy: An Invitation to Action*, January 1993, WSEO 92-158.

[2] RCW 43.21F.015(7)

Section A
Northwest Power Planning Council - *Study of Western Power Market Prices, Summer 2000, Executive Summary*

This section reprints the executive summary of the Northwest Power Planning Council's (NWPPC) Study of Western Power Market Prices Summer 2000, released in October 2000[1]. Washington utilities operate as part of a west-wide transmission and power supply system. Any understanding of the electricity supply and price issues faced by Washington utilities must be within the context of the western U.S. power market. This report provides that context. It also provides the Council's recommendations for how to mitigate the extreme price volatility that has characterized western power markets in 2000.

Introduction

Almost two years ago, the NWPPC initiated a study of the adequacy of the Northwest's power supply. This study was motivated by the observation that while the region had enjoyed several years of robust economic growth and, consequently growth in the demand for electricity, there had been very little in the way of new generation development. At the same time, efforts to improve the efficiency of electricity use in the region had been reduced dramatically because of the uncertainty of utility restructuring. This raised the concern that under conditions of high stress, the system might not be able to fully meet the region's power needs to serve load and to maintain the reserves essential to a reliable system. Conditions of high stress involve combinations of high weather-driven loads, poor hydropower conditions, and forced outages of thermal and hydropower generating units. The study was completed late last winter.[2] It concluded that:

- There is an increasing possibility of power supply problems over each of the next few winters (December, January, and February), reaching a probability of 24% by 2003. This takes into account both regional resources and the availability of imports. The level and duration of the possible shortfalls could be relatively small – a few hundred megawatts (MW) for a few hours – or quite large – a few thousand MW for extended periods.
- The region would need the *equivalent* of 3,000 MW of new capacity to reduce the probability to a more acceptable 5% level. That new capacity should take the form of new generation ***and*** economic load management, i.e., reductions or shifts in consumer loads that make economic sense for the consumer and the power system.
- It was unlikely that market prices would be sufficient to stimulate the development of sufficient new generation in that time frame. This meant that in the near-term, an even higher priority needed to be placed on developing economic load management opportunities.

While this study generated a good deal of interest, it has been difficult for people to get too concerned about probabilities generated by arcane computer models. This summer, however, developments in the power system have captured the attention of the industry and the public. Those developments resulted in unprecedented high prices in Western power markets, including the Northwest. Average prices for power traded for the heavy load hours of June 28th at the Mid-Columbia trading hub reached almost $700 per megawatt-hour (MWhr). This is more than 10 times the previous high and is consistent with the prices seen at other trading hubs in the West. Moreover, even for off-peak periods and days for which prices were not at extreme levels, they were considerably higher than past summers.

These prices have caused some economic hardship in the Northwest. The hardships have been limited by the fact that spot market purchases represent a small portion of the total amount of power consumed in Northwest. Relatively few retail customers purchase directly from the market or are on market-indexed rates. However, several industrial customers who are on such rates found it uneconomical to continue operation at these power rates. In addition, several utilities are seeking increases in their retail rates to cover the increased cost of power purchases. Because of these impacts, Governors Locke of Washington and Racicot of Montana asked the NWPPC to undertake a study to explain the reasons for the prices seen on the market and the actions that might be taken to mitigate these prices.

The NWPPC believes that the market prices seen this summer are a tangible manifestation of the fundamental problems identified in the NWPPC's power supply adequacy study of last winter. That is, the prices are an indicator of approaching scarcity. This summer, the system, which already is facing tight supplies, has been further stressed by combinations of unusually high loads, poor hydropower conditions, and forced outages of thermal units. There is little in the way of price-responsiveness in demand to mitigate these prices. Those who had available supply were able to ask for and receive high prices. This combination of factors is precisely what leads to the power supply adequacy problems identified in the NWPPC's earlier study. These factors apply not only to the Northwest but also to the entire Western Interconnected System. There were some additional factors acting this summer related to the design of the California market, but they should not obscure the basic underlying problem. Absent some action, the next similar event could result in not only high prices but also a failure of the system to meet loads.

In the following paragraphs we will summarize the evidence regarding the factors affecting Western market prices this summer, focusing in some detail on the last week in June, the period in which the highest prices were observed. We will then offer some recommendations for actions to mitigate future price excursions and potential power supply adequacy problems.

What Caused this Summer's Prices?

As noted above, we believe the prices experienced this summer are symptomatic of an overall tightening of supply, exacerbated by a number of factors. Some of these factors are physical and economic, others are related to the relative immaturity of the competitive electricity market and the uncertainties involved in the transition from a regulated structure. The physical and economic factors include:

- unusually high weather-driven demands throughout the West,
- an unusual pattern of hydropower generation,
- a high level of planned and forced outages of thermal generating units, and
- high gas prices.

The factors related to market immaturity and transitional uncertainties include:

- the lack of a demand-side price response in the market;
- inadequate utilization of risk mitigation strategies, and
- factors related to the design and operation of the California market.

Overall Tightening of Supplies

Between 1995 and 1999, WSCC peak loads increased by nearly 12,000 MW, or by about 10%. The increase would have been even more if 1999 hadn't been a relatively mild weather year. Generating capacity available during peak load months did not increase to keep pace with peak load growth. While peak loads increased by 12,000 MW from 1995 to 1999, generating capacity only increased by 4,600 MW.

We also believe that efforts to improve the efficiency of electricity use, i.e., conservation, have fallen off considerably in recent years. This is largely the result of the uncertainty created by the restructuring of the electricity industry. Utilities, who were the primary vehicle for conservation development, generally reduced their efforts because of concerns about creating potentially stranded investment if retail access resulted in the loss of customers. There were also concerns about the need to raise rates to cover conservation costs and the revenues lost as a result of conservation.

The effect of growth in demand outstripping the growth in resources is a narrowing of reserve margins. This implies more efficient utilization of existing capacity and was an anticipated benefit of moving to a competitive generation market. However, when it proceeds to the point of putting reliability at risk and destabilizing prices, it is a problem.

Physical and Economic Factors

High Peak Loads

The period of the highest prices coincided with a period in which loads in the Northwest, California and the Desert Southwest were at high levels as a result of high temperatures throughout the West. In the Northwest, peak loads were approximately 3,400 MW greater than last year while in California on the same day loads were approximately 1,400 MW higher. [California and the U.S. portion of Northwest Power Pool (NWPP) combined, increased 4,826 MW from the peak on June 30, 1999, to the peak on June 28, 2000, both Wednesdays.]

Unusual Hydropower Production

While the summer of 2000 was expected to be a more or less normal year in terms of overall runoff in the Northwest, the runoff came in an unusual pattern. Runoff in the early spring was somewhat higher than usual. But in May and particularly in June, the runoff and hydropower generation was less than normal and much less than 1999. Hydropower generation in late June was approximately 6,000 MW less than the same time in the previous year.

Planned and Forced Outages of Thermal Units

Maintenance on thermal generation is frequently planned for the May-June period when abundant hydropower is typically available. In addition, plants do break down, sometimes when it is least desirable to do so. We have attempted to identify Northwest thermal units that were either on planned or forced outage status during the last week of June. This was done by examining the generation data reported to the Western Systems Coordinating Council (WSCC) or sup-plemental data that was provided by Northwest generators. These combined data sets comprise about 85% of the capacity in the Northwest. From these data it appears that approximately 1,670 MW of capacity was out on a long term basis, either planned or extended forced outages, and another 3,400 and 2,700 MW experienced short-term forced outages on the 27th and 28th respectively. Total generation, thermal and hydro, for the last week of June was approximately 4,000 MW below the levels of 1999.

Load/Resource Balance for the Northwest

A preliminary analysis of loads and resources for the Northwest Power Pool - US Systems for June 28, the peak price day of June, indicates a peak net hourly load (native load plus exports) of about 41,000 MW. We were unable to identify more than 38,000 MW of capacity, including imports, available to meet these loads. This analysis has a high level of uncertainty (hourly operating data was available for about 85% of installed capacity and the output of the remaining installed capacity had to be estimated and data errors are possible). Obviously, since the lights did not go out, the system was able to balance loads and resources. It is likely that data errors and errors in our estimates for the non-reporting generators are at fault. Nonetheless, the evidence strongly suggests that the Northwest was operating under near-deficit conditions during the heavy-load hours of that day.

Gas Prices

Between the summer of 1998 and the summer of 2000 natural gas prices at Sumas (on the Washington-British Columbia border) increased from about $1.50 per million Btu to $3.30. Prices into Southern California increased over the same period from about $2.40 to $4.18. Prices have moved substantially higher during late August and September. During mid- September, prices at Sumas were $4.60 and prices into Southern California were over $6.00, although the California prices were affected by a serious pipeline explosion.

Higher natural gas prices, should they persist, will result in higher "normal" prices of electricity. Depending on the generating technology used, a $2 dollar increase in natural gas prices (roughly consistent with the doubling of gas prices seen by mid-summer) could increase electricity prices by between $15 per megawatt-hour and $22 per megawatt-hour. Average electricity prices during high load hours in the Pacific Northwest mid-Columbia market increased by $140 per megawatt-hour between June 1999 and June 2000, and light load hour prices increased by $46. The comparable price increases in Southern California were $113 and $28. The increase in natural gas prices can not come close to explaining the observed increase in electricity prices.

Factors Related to the Immaturity of the Competitive Electricity Market and the Uncertainties in the Transition from a Regulated Structure

Lack of Price Responsive Demand

A systemic problem associated with the immaturity of the competitive electricity market is the lack of a demand side to that market. Price responsive demand is important to an efficiently operating competitive market. Price responsiveness is an essential mechanism to balancing supply and demand. Without some degree of demand responsiveness, there is no check on the prices that can be charged when supplies are tight, except for artificial caps. This is particularly critical when supplies are stretched to their limits. Under those circumstances, a relatively small degree of price responsiveness can have a relatively large reducing effect on prices, and could also mean the difference between maintaining service and curtailments

Currently, at any given hour, the amount of electricity demand is virtually independent of wholesale price. This is because the vast majority of electricity consumers do not see market prices in anything approaching real time and, for the most part, have done little if any thinking about how they could reduce their demands if power were very expensive. The NWPPC is not advocating retail access as means of achieving price responsiveness. The states are making their decisions about when and how much to open their retail markets to competition. But developing price responsive demand does not require passing real-time market prices on to all consumers. It does mean, however, that those the suppliers who do see wholesale prices should act as intermediaries between the market and consumers to effect load reduction or shifting that is in the mutual economic interest of the consumer and the power system. We believe this will develop in time and that the current high prices will help motivate that development. However, given the tight supplies and high prices now affecting the market, the NWPPC believes that special effort should be devoted to encouraging and facilitating the expedited development of the demand side of the market now.

The California Effect

Among the Western States, California's electricity industry is farthest down the restructuring path. Their path is, in many ways, quite different than most other examples. They have created a market structure that is quite centralized and quite complex. For most of its three-year life, the California market demonstrated competitive power prices. However, under periods of stress, we believe there are characteristics of the California market structure and the incentives it creates that arguably result in prices that are higher than they might otherwise be. The California Independent System Operator (ISO) and experts acting in an advisory capacity to the ISO have identified these characteristics. These include restrictions on the ability of California utilities to enter into longer-term contracts, thus forcing most loads into day-ahead and hour-ahead spot markets operated by the California Power Exchange. Other facets of the market design create incentives that, when supplies are tight, result in as much as 20% of the load being met in a real-time market operated by the ISO. This is not a situation conducive to moderating price spikes. We know California is studying these issues and we are hopeful that they will resolve them in a satisfactory fashion.

Did Market Participants Manipulate the Market?

Much is made of market participants exercising market power during this summer's price spikes. Clearly the prices we have seen are well above a "competitive" price, if that is defined as the operating cost of the most expensive unit on the system that must run to meet load. The ability of market participants to ask for and receive more than the competitive price can be defined as market power. However, this is also the normal functioning of a market when supplies are tight and there is no moderating effect of price responsiveness. It is neither illegal nor immoral.

The NWPPC did examine the generating records of most Northwest power plants to see if there was evidence of manipulating the market by "withholding," i.e., holding power off the market to drive up prices. We found no clear evidence of such behavior. Power plants were generally being operated as one would expect given the characteristics of the plants. Hydro plants were typically following load. Thermal plants were typically running "flat out" or, in the case of units with higher operating costs, backed down during the off-peak periods. Where there were operating patterns that might be interpreted as withholding, the quantities involved were too small to affect the market.

The NWPPC did not have access to information that would permit analysis of the bidding strategies of different market participants. We do not know whether that information would suggest market manipulation.

Recommendations

Encourage the Greater Use of Risk Mitigation Mechanisms

One of the characteristics of a commodity market is the emergence of mechanisms to manage risk, and electricity is rapidly becoming a commodity market. These mechanisms include actual physical longer-term contracts for supply, futures contracts, financial hedging mechanisms, and so on. These mechanisms can limit exposure to high prices. At the same time, however, there is always the risk that they will prove more costly than the spot market. Risk mitigation comes at a cost, and it is not realistic to be fully hedged for all risk. But the experience of this summer suggests there could be greater use of risk management tools.

As noted earlier, we believe the limitations on forward contracting by California utilities was a contributing factor to the price extremes of this summer. We believe the same is true of other market participants in the Northwest and elsewhere. While opportunities to enter into forward contracts and other hedging arrangements have existed, it may be that the protracted period of low market prices for electricity lulled some market participants into believing they had no need of such mechanisms. Recognizing the commodity nature of the electricity market and taking appropriate steps to protect against the upside risk is important. Had more market participants done so, it is likely that this summer's price volatility and its impacts would have been moderated. Forward contracting is also a vehicle by which new entrants in the generation market can limit their downside risk, thereby facilitating the development of new generation.

Evaluate the Need and Options for Further Encouraging Generation Development

As noted earlier, the NWPPC's analysis of power supply adequacy indicated that market prices would not be sufficient to support the development of "merchant" power plants, i.e., plants selling into the spot market exclusively, until 2004. The NWPPC has also done analyses looking at actual market prices over the past year to see if prices had been sufficient for a new entrant to cover its variable operating costs and its fixed costs and earn a reasonable rate of return. Until this summer the answer has been "no."

With the electricity and gas prices experienced over the past year, the answer has become "yes." With the higher prices, a couple of plants not considered in the NWPPC's adequacy study have begun construction. In the Northwest, there are now 1,276 MW of capacity under construction that should come on line in 2001 through 2002. There are another 2,977 MW that already have site certificates, 1,291 MW of which we judge to be "active" projects, and another 3,060 MW that are in or have begun the siting process. The siting process does not appear to be a problem in that there is a backlog of sites that have been permitted and many more in the process. Almost all of these are natural-gas-fired combustion turbines, and nearly all of them are located within reasonable proximity to natural gas pipelines and transmission lines. There is a similar story to be told elsewhere in the West.

The degree of developer activity is encouraging. However, if we were to experience a couple years of relatively warm, wet winters and cool summers with good hydro conditions, market prices would probably fall and many of the active projects might become inactive. If followed by a dry spell and a hot summer or a cold winter, we would be up against the supply limits again.

The question this possibility raises is whether we can rely on the market to provide sufficient capacity for reliability purposes. And if not, what are the options for assuring that there is capacity available to assure reliability and mitigate excessive price spikes? The NWPPC intends to pursue this question.

Accelerate Efforts to Develop the Demand Side of the Market

While the lead-time for the development of new combined cycle generation is relatively short, development will take some time. During that time, the region and the West are vulnerable to further price spikes and possible reliability problems. Moreover, it is not certain that the long-term market will support the level of development necessary to assure adequate reliability. Developing the demand side of the market has the potential for somewhat shorter lead times. Price-responsive demand can help mitigate price spikes and potentially avert reliability problems.

The Northwest has a great deal of successful experience in increasing the efficiency of electricity end-use as a resource. The region needs to reinvigorate those efforts in light of the market prices we are experiencing. There are cost-effective means of slowing the growth of demand that should be exploited. However, the region in particular needs to move aggressively to implement price-responsive demand management – reducing loads during periods of high prices or shifting the loads to periods of the day where prices are less. The bad news is that this region has relatively little experience with these approaches, although that is changing. The good news is that there should be significant untapped potential.

The NWPPC believes that market-like mechanisms wherein the consumer receives a significant part of the benefit will be most effective. Pilot programs have been initiated this year in the region in which the serving utility and the load-reducing consumer share the cost savings of avoided power purchases (or the revenues from selling the freed-up power on the market). These programs appear to have been successful although limited in scope. The greatest potential for such partnerships probably exists within industry and large commercial buildings. What can be done will vary from building to building and process to process. Nevertheless, if provided the incentive, the NWPPC believes people will rise to the challenge. Creating these incentives should be a priority for the utilities of the region.

California Should Correct the Incentives in their Market Structure that Contribute to Excessive Prices and Volatility

The NWPPC believes that the California ISO and others in the California market have done a credible job of identifying the barriers and incentives created by their market structure that have contributed to excessive prices and price volatility. We know the issues are complex and politically volatile. We hope that the state can move quickly to correct these problems.

At Least Until the Market Matures, Data for Monitoring and Evaluating the Performance of the Market Should be Available on a Timely Basis

One thing that the experience of this summer has shown is that it is difficult to obtain the data necessary to monitor and evaluate the performance of the market. Despite the fact that utilities in the Northwest were extremely cooperative, there was a delay of many weeks before the relevant data could be obtained. While the WSCC maintains a data base of generation and transmission loading data, not all generators report to the system and of those that do, the data link is not necessarily carefully maintained. Despite incompleteness data, the WSCC has chosen not to release the information to independent body like the NWPPC, even when it agreed to keep the data confidential and to use the data in such a way that individual plants could not be identified. We understand the possible commercial sensitivity of some of this information. We believe, however, that there should be arrangements possible that both protect the commercial value of the information and make it possible for responsible independent parties to evaluate market performance on a timely basis. At least until the market has matured and the public has greater confidence in its operation, this should be a high priority for market participants and organizations like the WSCC, the California ISO and regional transmission organizations as they are formed.

Electricity Emergency Process and Procedures Need to be in Place

If we are correct is our assessment that the electricity market prices experienced this summer are a warning of approaching scarcity, then establishing the processes and procedures that would be used in the event of an actual supply emergency should be a priority. Until new generation comes on line and demand-side programs can be implemented, there is significant probability that our emergency readiness will be tested. Necessary elements include an inventory of the actions that could be taken, the trigger points for taking these actions, clear definition of roles and responsibilities, and a communications plan to inform the public. We are pleased that efforts to accomplish this are underway involving the Pacific Northwest Utilities Conference Committee, the Northwest Power Pool, Bonneville Power Administration, the NWPPC, the Northwest states and region's utilities.

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[1] The full report, plus additional background information is available at the Northwest Power Planning Council's website: http://www.nwppc.org/adeq_toc.htm. Council Document 2000-18.

[2] *Northwest Power Supply Adequacy/Reliability Study, Phase 1 Report*, Paper 2000-4, Northwest Power Planning Council, March 6, 2000, Council Document 2000-4..

Section B
Transmission

Introduction

The institutions that govern the regional electricity transmission grid which serves Washington and other western states are in the midst of a significant restructuring. As a result of changes in federal policy and ongoing industry-sponsored processes here in the west, new institutions are forming that will fundamentally alter the way the transmission system is governed, operated, planned, and expanded.

Transmission systems have traditionally been owned and operated by vertically integrated utilities which use them to deliver power from their own generators to their distribution systems. The Bonneville Power Administration (BPA) owns and operates some 80% of the high-voltage transmission line-miles in the four Northwest states. Additional transmission systems are owned by publicly-owned utilities and investor-owned utilities under the regulation of state public utility commissions, and the Federal Energy Regulatory Commission (FERC). Grid reliability is maintained through a system of voluntary rules developed by industry organizations.

In the 1990s, the federal focus shifted to facilitating a competitive wholesale power market. New federal rules required utilities to open up their systems to use by competitors, and encouraged the formation of new regional entities for managing the region's power grid, while in 1999 legislation was introduced in Congress to establish mandatory, enforceable reliability rules.

While transmission costs account for only about 10% of the typical retail electric bill in Washington, the policies that govern the electricity transmission grid can affect the public interest in a number of significant ways. Ensuring that the interstate transmission grid is operated reliably is the most obvious, and most important. Outages on the transmission grid have the potential to affect power supplies for millions of customers, and can result in economic losses in the billions of dollars. Transmission policies are also extremely important for the development of new generating resources, as the availability and price of transmission will affect the timing and location of new power plants. Transmission policies can either encourage or discourage the development of new renewable resources and alternatives to new transmission lines such as demand-side management and distributed generation. For these and other reasons, it is critical that the public has involvement in major decisions regarding the planning and operation of the region's transmission system.

Changes in grid management organizations are largely proceeding on two parallel tracks: the efforts by regional utilities to form a Regional Transmission Organization, RTO West, in response to the FERC's Order 2000; and an effort to merge a number of industry groups dealing with reliability and commercial practices into a single westwide organization.

Background

The current grid management system began to take shape in the mid-1960s, after the interconnection of the western system was completed. The Western Systems Coordinating Council (WSCC)[1] was formed in 1967 in the wake of a blackout in the Northeast that left almost 30 million people without power. The WSCC is one of ten regional reliability councils that operate under the auspices of the North American Electric Reliability Council (NERC)[2]. The goal of NERC is to enhance the reliability of the bulk power system through the development of voluntary standards that govern the way interconnected utility systems interact with each other. The WSCC is the only regional reliability council that governs an entire electrical interconnection (See Figure 1).

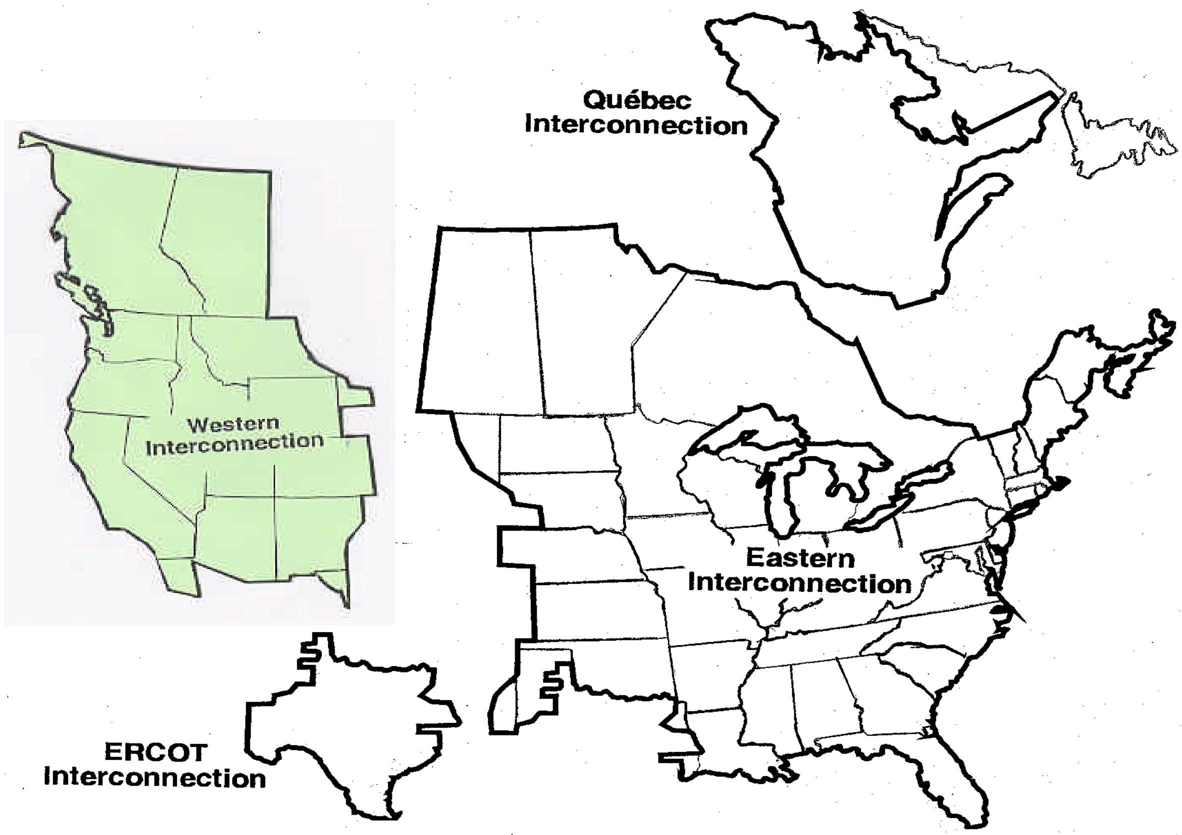

Figure 1. Electrical Interconnections in North America

With the passage of the Energy Policy Act of 1992 and subsequent policy direction from the FERC[3], industry attention turned from simply maintaining bulk power system reliability to facilitating commercial transactions among utilities and growing numbers of independent power producers (IPPs), power marketers, and other non-utility entities. The Western Regional Transmission Association (WRTA)[4],

Northwest Regional Transmission Association (NRTA)[5] and Southwest Regional Transmission Association (SWRTA)[6] were formed in the mid-1990s with the explicit goal of facilitating "open access" to utility transmission systems. Members of the RTA's are obligated to file open access tariffs if requested by another member, and are subject to mandatory dispute resolution over the terms of such access.

Order 888 and IndeGO

The goal of open access was furthered in 1996 when FERC issued Order 888 ("Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities")[7]. Order 888 and its companion Order 889[8] required each utility to post any transmission capacity not needed to serve their own customers under state-regulated retail tariffs ("available transfer capability" or ATC) on an on-line bulletin board, and to sell such capacity to any qualified customer under standard terms spelled out in a FERC-approved tariff. Further, the orders required utilities themselves to reserve capacity on their own systems under the same FERC-approved tariff for their customer's use. This requirement was intended to blunt the advantages utilities enjoy in the wholesale market by virtue of owning and operating high-voltage transmission systems.

Order 888 did not require utilities to form Independent System Operators (ISOs), but it did encourage utilities to consider taking that step. ISOs are independent organizations which take over operation but not ownership of the high-voltage transmission systems of several utilities. The Order also contained a number of recommendations should utilities decide to form ISOs voluntarily.

The Northwest began to have earnest discussions about forming an ISO beginning in 1995. The 1996 Comprehensive Review of the Northwest Energy System[9] sponsored by the four Northwest governors recommended that an ISO be formed in the Northwest, comprising the high-voltage systems of the BPA and the region's Investor-owned Utilities (IOUs). In August of that year, the six IOUs announced their intention to form an ISO called IndeGO. The IOUs were soon joined by BPA and a number of publicly-owned utilities, in addition to utilities in Colorado and Wyoming. Negotiations during 1997 produced a proposal that contained many of the elements that FERC would later include as requirements for Regional Transmission Organizations (RTOs) in Order 2000, including an independent governing board, sole authority over real-time grid operations and a market mechanism for allocating access to the grid during times of heavy use. However, concerns about cost shifting and the lack of perceived benefits in a region which is heavily dependent on low-cost hydroelectric power led to the proposal's abandonment in early 1998.

Merging Western Grid Management Organizations

The shelving of the IndeGO proposal did not end momentum to reorganize the institutions that manage the western grid. While the formation of the RTAs filled the need for a forum in which users of the grid could discuss commercial issues, it was recognized early on that issues which had traditionally been thought of as "reliability issues" could have enormous commercial ramifications while certain commercial practices could well have an impact on grid reliability. In 1997, the RTAs, the WSCC, the Colorado Coordinated Planning Group, and the Committee on Regional Electric Power Cooperation (CREPC) (a committee of the Western Governor's Association consisting of energy agencies and utility regulatory commissions in western states and provinces, including the OTED Energy Division)[10] formed the Western Interconnection Forum (WICF)[11], an ad-hoc group whose role was to coordinate among the various organizations and to study whether and how to combine them into a single, west-wide grid management organization.

Meanwhile, a NERC-sponsored "Blue Ribbon Reliability Panel" were recommending changes in the way reliability is governed at the national level.[12] The commission recommended that Congress pass legislation granting the authority for setting mandatory reliability standards to a new, self-regulating reliability organization (SRRO). The new body, to be called the North American Electricity Reliability Organization (NAERO), would supplant NERC and would provide an umbrella under which regional reliability organizations (RROs) would enforce standards set by the NAERO. Western interests, including states and provinces, pushed for additional deference to standards set by RROs that encompass entire interconnections, such as the WSCC, and for a greater role for states and provinces in the governance of RROs and in the standard-setting process. Legislation (S.2071 Electric Reliability 2000 Act) to accomplish all this passed the United States Senate in 2000, but stalled in the House of Representatives.

The WICF work group met throughout 1999 and into 2000 to develop a proposal to create a western RRO, provisionally dubbed the Western Interconnection Organization (WIO). The WIO would mirror the structure and functions of the NAERO, setting reliability standards for the western interconnection, and addressing commercial issues through a market interface committee. Work was completed on this proposal in the fall of 2000. The proposal was endorsed by the CREPC and the WRTA in October of 2000, and by NRTA in November, with additional presentations to the other organizations scheduled. Regulatory approval is expected in mid-2001, with incorporation and merging of existing entities by the end of 2001. More information about the proposed WIO can be found at http://www.wrta.net/wicfdocs.htm.

Order 2000 and RTO West

While FERC's Order 888 contained a number of recommendations for the formation of ISO's, it did not explicitly require that utilities take that step. Several ISOs did form around the country, mostly in regions where states had opted to restructure their retail markets. By 1999, ISOs were operating in California, New England, New York, and the PJM region (consisting of Pennsylvania, New Jersey, Maryland, and Delaware), and discussions were underway in the Midwest and Desert Southwest. In 1999, FERC undertook a series of conferences, informational proceedings, and consultations about the next steps for transmission restructuring. These led to the issuance of a notice of proposed rulemaking (NOPR) in May of 1999. In the NOPR, FERC proposed that utilities be required by October 15, 2000, to file plans to form RTOs, to be operational by December 15, 2001. Utilities would also be given the option to make alternative filings consisting of explanations for why they were not filing RTO plans. The rulemaking was finalized in December of 1999, as Order 2000.[13]

Northwest parties had been discussing a variety of options for future transmission organizations, from an independent grid scheduler, which would do little more than serve as a clearinghouse for transmission capacity, to a "TransCo", which would own and operate the region's high voltage grid. In March of 2000, nine transmission-owning utilities ("filing utilities") kicked off a public process that led up to the October 16 filing of RTO West.[14] The filing utilities are Avista Corporation, BPA, Idaho Power, Montana Power, Nevada Power, PaciCorp, Portland General Electric, Puget Sound Energy, and Sierra Pacific Power. Only the eight investor-owned utilities are subject to FERC jurisdiction and, hence, to the requirements of Order 2000, but BPA participated on a voluntarily basis. The utilities formed a "regional representatives group" (RRG) of stakeholders to advise the filing utilities as they prepared a filing that would meet the requirements of Order 2000. Stakeholders represented on the RRG included independent generators, power marketers, several different groupings of publicly-owned utilities, end-use customers representatives, environmental and renewables advocates, and state and provincial energy agencies. Given the lack of time before the October 16, 2000, deadline, the parties were to use the IndeGO proposal as a jumping-off point. The filing utilities also issued consensus statements regarding the form, structure, and functions of the proposed RTO to further frame the debate.

The proposal that emerged from this process will, if accepted, fundamentally alter the way the bulk power system is operated and the way expansions of the system are planned and financed. Traditionally, transmission systems have been owned and operated by vertically integrated utilities which use them to deliver power from generators they own to distribution systems they own. Operational decisions are made with an eye towards minimizing company-wide costs, subject to voluntary constraints on the way in which operations can affect neighboring systems. Investment decisions are made within a regulatory framework that, in theory, offers similar incentives for competing investments, whether they involve new generation, transmission, or demand-side management.

This model began to change with the movement towards a competitive wholesale power market, and as utilities began to rely on purchases from independent suppliers to meet load growth rather than investing in new resources of their own. The decentralization of the generation planning and investment process, coupled with continued uncertainty on the part of vertically-integrated utilities as to the nature of their relationship with retail customers over the long run, calls into question whether existing planning processes are adequate to provide for the infrastructure needs of tomorrow's industry.

RTO West would complete the transition to a new industry structure in which the transmission system would be operated by an entity that is independent both from generators and from retail energy service providers. RTO West would be governed by a nine-member board of directors, who can have no financial ties to any member company. While principle responsibility for planning and constructing local transmission facilities would remain with participating transmission owners, RTO West would have a role in planning main grid additions, and would have backstop authority to compel a transmission owner to construct a facility that is needed by a third party. Facilities whose primary purpose is to facilitate power trading, rather than to provide reliable service to load, would be financed through some sort of market mechanism, rather than by existing transmission ratepayers.

Operationally, the biggest changes would be in the way transmission capacity is reserved and in how ancillary services are procured. Currently, transmission service is purchased under a hodgepodge of long-term contracts and shorter term arrangements under Order 888 tariffs. Generators that wish to schedule power to a neighboring control area must pay a cost-based transmission tariff to obtain transmission service to a control area boundary. Additional tariffs must be paid to each control area operator between the generator and its customer, resulting in one or more transmission rate "pancakes". Ancillary service products such as regulation and operating reserves are provided for a fee by transmission owners, from their own generators if they prefer. Transmission rights are not easily tradable, which means that if transmission schedules need to be curtailed due to "congestion" (when there is more demand for transmission capacity than the system can accommodate), higher-value transactions can be bumped in favor of lower-value ones. Further, because transmission schedules don't reflect the way the power actually flows across the grid, curtailments may affect many more megawatts of schedules than is necessary to solve the problem.

In accordance with Order 2000, RTO West would institute a market-based system of rationing access the grid during times of congestion, using Firm Transmission Rights (FTRs) across designated "flowpaths" (transmission paths that experience "commercially significant" amounts of congestion). FTRs would be standardized, tradable instruments representing the right to transmit a specified amount of power across a particular flowpath in a particular direction, including standardized provisions in the event of facility outages. Aside from purchasing the necessary FTRs and providing transmission losses, there would be no charge to schedule across the grid. Establishing standardized, tradable transmission rights and eliminating pancaked transmission rates is meant to facilitate the development of a more liquid short-term market for transmission capacity, making it much more likely that scarce capacity will be allocated to the highest value use and enhancing the efficiency and competitiveness of regional power markets.

This cannot be accomplished without some impact on existing uses of the grid. Eliminating pancaked rates requires changes in the current system of allocating the fixed costs of the transmission system. Similar to the IndeGO proposal and the methods used by other ISOs, RTO West is proposing fixed, annual load-based "access fees" based on the load's contribution to monthly peak demand. However, while the IndeGO proposal would have blended costs within certain areas over a ten-year period, resulting in transmission rate changes for some utilities of up to 0.2 cents per kilowatt-hour, RTO West opted for a system of "company rates" which it hopes will mitigate cost shifts to the maximum extent possible. Historical payments between utilities associated with transmission capacity or "wheeling" arrangements are converted into "transfer payments" which will continue for at least ten years. Utilities with pre-existing contracts or load-service obligations may also be allocated FTRs commensurate with those obligations.

In the October filing, the filing utilities asked FERC for a declaratory order by January 31, 2001, with respect to certain governance documents including the Articles of Incorporation and the By-laws, and whether the scope and configuration of the RTO as proposed meets FERC standards as articulated in Order 2000. A "Stage 2" filing will be prepared in the spring of 2001 that will contain significantly more detail about various aspects of RTO West operation such as congestion management, market design, and roles of various parties in planning and expanding the system, as well as a timetable for RTO West to begin operations. Additional filings with state regulatory commissions will probably occur after the Stage 2 FERC filing. RTO West is not expected to be operational before mid-2002.

TransConnect

In addition to forming RTO West, six of the filing utilities are also proposing to divest their transmission assets to a new company called TransConnect, LLC. The six TransConnect utilities are Avista Corporation, Montana Power, Nevada Power, Portland General Electric, Puget Sound Energy, and Sierra Pacific Power. TransConnect would be wholly owned by the six participating companies, in shares equivalent to the value of the assets contributed. A separate company called TransConnect Corporate Manager, Inc. would be formed as a publicly traded corporation for the purpose of operating the facilities owned by TransConnect, LLC. The TransConnect utilities hope this arrangement will meet FERC's requirement for independence for a transmission-only company, and that this will allow TransConnect to take on certain of the RTO functions specified in Order 2000. TransConnect's October 16 filing describes an enhanced role in the system planning and expansion process and its intention to file for some form of performance-based ratemaking, which may entail incentives to operate the systems more efficiently and/or more reliably. The TransConnect companies have asked the FERC for a declaratory order in 2001, that the proposal for governance meets the requirements of Order 2000, and that the functions TransConnect proposes to take on are acceptable.

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[1] For more information about the WSCC, see http://www.wscc.com.

[2] For more information about NERC, see http://www.nerc.com.

[3] For more information about FERC, see http://www.ferc.fed.us.

[4] For more information about WRTA, see http://www.wrta.net.

[5] For more information about NRTA, see http://www.nrta.org.

[6] For more information about SWRTA, see http://www.swrta.org.

[7] http://www.ferc.fed.us/news1/rules/pages/order888.htm.

[8] http://www.ferc.fed.us/news1/rules/pages/order889.htm.

[9] http://www.nwppc.org/crfinal.htm.

[10] For more information about CREPC, see http://www.westgov.org/wieb/crepnew2.htm.

[11] For more information about WICF, see http://www.wrta.net/wicfindx.htm.

[12] For more information about the NERC Blue Ribbon Reliability Panel, see http://www.nerc.com/~blue/index.html.

[13] http://www.ferc.fed.us/news1/rules/pages/order2000.htm.

[14] For more information about the RTO West public process and proposal, see http://www.rtowest.com.

Section C
Regional Electricity Issues and the Bonneville Power Administration

Volatility turning into stability and then turning once again into volatility is a good way of characterizing the last two years of the Bonneville Power Administration's (BPA) financial and political condition. Since over one-half of all electricity sold in Washington comes from BPA, Washington has a large stake in BPA's financial and political health. This section summarizes the current status of key issues confronting both BPA and the state of Washington.

Subscription and Rates

Following the recommendation of the Comprehensive Review of the Northwest Electricity System in 1996,[1] BPA developed a Strategy for how its customers would "subscribe" or sign up for the power products it sells. The final subscription strategy, which was released in December, 1998, set forth the principles under which power would be sold to the various customer groups, how much power each would get, and what products BPA would offer for the rate period from October 1, 2001, to September 30, 2006. BPA then conducted a formal rate case that implemented the subscription strategy and set the rates for its power products.[2] The rate case concluded in the Spring of 2000 but before BPA could send its final documentation to the Federal Energy Regulatory Commission (FERC), prices for market power on the West Coast rose precipitously, rendering the cost projections for its own power purchases out of date and causing a surge in demand for BPA preference power by Northwest public utilities.

BPA, after another regional consultation, reopened its rate case and published a new version of its Cost Recovery Adjustment Clause (CRAC) which includes a 15% rate increase at the outset and will allow BPA to raise rates further if its financial reserves are projected to fall below specified levels. The proposed rate structure will place BPA's preference firm rate, the rate at which it sells wholesale power to consumer owned utilities, at 25.5 mills/kWh (or $0.025/kWh). While high for BPA, this rate is well below average wholesale long-term contract rates almost everywhere in the United States and well below current and expected wholesale market prices. (See Figure 2[3]) The rates are now expected to be final by spring, 2001. In the meantime, BPA has executed contracts with all of its Pacific Northwest customers who will have the opportunity to change their minds if the final rate schedules are not to their liking. Since BPA preference rates are likely to be below projected prices for power from other sources, it is unlikely that any customers will change their minds. There is still controversy over how power is allocated among customer classes and whether the customer classes are treated fairly. For example, the economic viability of many of the direct service customers, principally aluminum smelters, is very much in question and they want some relief. There is also a risk that higher West Coast wholesale electricity prices will drive the cost of BPA's power purchases high enough to lessen its competitiveness.

These straightforward narratives of administrative process belie the intense negotiations and even conflict that has accompanied the issue every step of the way. Seven major issues stand out. In most cases, Washington has been supportive of BPA's attempts to find a middle path among the contending forces. This is not surprising since Washington citizens are the biggest beneficiaries of BPA power and Washington contains all the contending regional interests within its borders. The issues are:

1. **The battle among customer groups, public utilities, aluminum companies, and the residential customers of the investor owned utilities for shares of preference power**

   Since BPA has not acquired any new generation resources in many years and

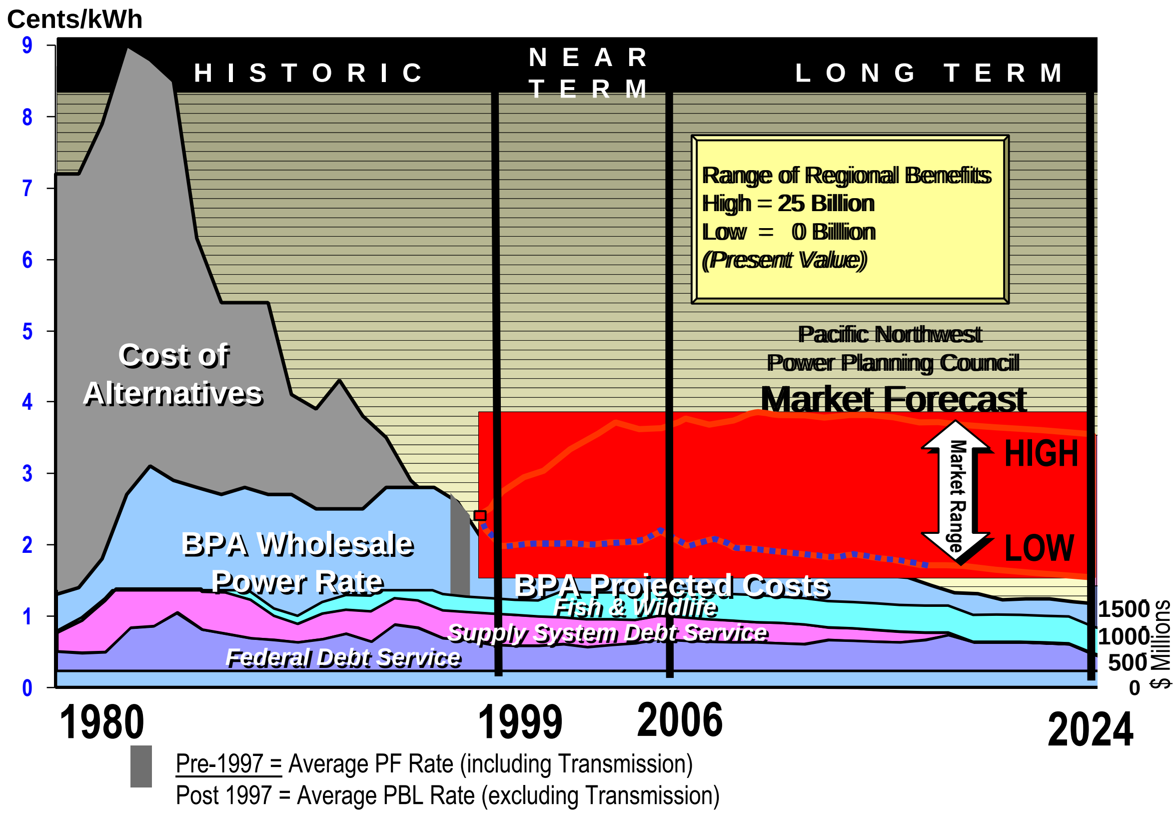

Figure 2. BPA Cost Based Rates and Range NWPPC Forecast Rates

Source: BPA, June 1999

operation of the hydro system for fish recovery has reduced its available power, BPA supplies less and less of regional power demands. On the other hand, demand continues to rise and as BPA becomes cheaper and cheaper relative to other resources (despite the rate increase), all customers want larger shares. BPA ultimately proposed to meet all public power loads (it is required to by law), half of residential Investor Owned Utilities (IOU) loads (partly with power and partly with an equivalent payment in cash), and about half of aluminum company loads. This was a shift away from aluminum companies toward residential customers of IOUs, while raising rates for all of its customers since BPA will have to buy power on the market to meet all of its commitments.

2. Fish costs

Generally environmentalists and tribes wanted BPA to leave room in its rates for higher costs and expenditures for fish recovery up to and including the costs of removing the four lower Snake River dams. All customer groups generally supported lower financial commitments to fish and wildlife recovery. BPA pretty much split the difference and neither set of interests came away fully satisfied.

3. Slice

Responding to requests from public utilities that generate much of their own power, BPA agreed to sell some power as “Slice.” Slice means “slice of the system” and purchasers agree to receive a fixed percentage of the output of the system (rather than a fixed amount of electricity) at any time and, in return, commit to pay that same percentage of BPA’s costs. The negotiations over Slice were both highly technical and political. The political issues produced some familiar fissures. Washington supported ten year contracts on the grounds that a longer term is essential to even out the risks to both BPA and the utilities while Oregon and California argued that such long contracts would lock up the system and make it harder to make the policy and governance changes they sought. There were new disagreements as well. Since Slice contracts benefit those public utilities who generate some of their own power while also buying from BPA (they are known as partial requirements customers), the full-requirements customers (those generally smaller utilities who buy all of their power from BPA) were afraid that the Slice "product" would shift more of BPA's costs to them. Ultimately, BPA again found a compromise: rules that satisfied the full-requirements customers, a contract length of ten years, but a cap of how much electricity could be sold as Slice, 2000 aMW.

4. Contract length

The controversy over the length of Slice contracts was part of a larger controversy over the length of contracts in general. BPA is authorized to sign contracts of up to 20 years and, until recently, all contracts were routinely twenty years long. The new subscription process and rate case came about because of the expiration of the twenty-year contract period that began on October 1, 1981, (although all of the aluminum companies and many utilities had renegotiated the terms of their contracts in 1996.) Washington State generally supported the full-requirements customers and other utilities that wanted very long-term contracts in the belief that one of the best ways to preserve the benefit of the Federal Columbia River Power System (FCRPS) for the state and region is to make a long-term commitment to it. Generally all interests that sought changes in how the system is governed and how the benefits are distributed preferred shorter contracts. Thus, Oregon and Montana, aluminum companies, members of congress from the Northeast and Midwest states, and California, and tribes wanted contracts of three to five years. Ultimately, BPA signed contracts of up to ten years with utilities that wanted them and five-year contracts with aluminum companies.

5. Restructuring

Restructuring legislation in Oregon and Montana caused more interstate tensions. In Montana, there was confusion about what utility, if any, should serve the former customers of the Montana Power Company and how the BPA residential exchange process should be handled. The Montana legislature authorized a buyers cooperative to purchase power on behalf of residential and small business customers formally served by Montana Power but BPA refused to acknowledge it as a utility because it did not own utility poles and wires. Consumer owned utilities in the region (and the state of Washington) strongly supported BPA, but Oregon, which has considered creating a similar mechanism to buy power on behalf of its own IOU customers, supported Montana.

Oregon's restructuring law caused its own complications because it encouraged its IOUs to divest themselves of some of their resources, thus reducing their "net requirements" and hence their eligibility for power purchases from BPA. Oregon's law also contains a provision that requires the Oregon Public Service Commission (PSC) to place a hold on the implementation of the restructuring if it appears the Oregon consumers would not receive the benefits from BPA to which they would otherwise be entitled. Ultimately, BPA found pathways to get residential exchange benefits to Montana and Oregon consumers without changes in BPA rules. In the case of Montana, all parties agreed that any successor utility to Montana Power would inherit Montana's share of residential exchange benefits. In the case of Oregon, BPA and the PSC agreed to adjust the manner in which residential exchange benefits were conveyed to

Oregon IOUs so that they could obtain the benefits in the form of more monetary equivalent payments and less in the form of actual electricity deliveries. This would have no effect on the rates Oregon customers paid but would not violate BPA's statutes regarding "requirements."[4]

6. **New public customers**

Although consumer or publicly owned utilities have the first right to BPA preference power, there have been no new consumer owned utilities created in many years. With changes in the electricity market brought about by restructuring, there is now renewed interest. BPA set aside a limited amount of subscription power for entities that want to qualify as preference customers. The Yakama Indian Nation and the City of Missoula (Montana) are among the entities most likely to qualify by acquiring a distribution system and having a financial and administrative apparatus that meets federal requirements.

7. **Conservation and renewables**

BPA included a modest conservation and renewables discount program in its new rate structure and is working on a plan to replace about 5% of its power purchases with conservation. Public interest groups and many utilities have been disappointed with both the low targets and low financial support for these programs and are dubious about the proposed implementation procedure. Washington Energy Policy staff have generally agreed. However, the conservation and renewables discount program rests on the excellent analytic work of the Regional Technical Forum, which Washington strongly supported and participated in. There seems to be universal agreement that, on this, BPA's money was well spent.[5]

Supply/Price/California/ Emergencies

Low water, high demand from California, and increased Northwest loads stretched the Federal Columbia River Power System to the breaking point during the summer of 2000. Coupled with tight electricity supplies, fast rising natural gas prices sent market prices for electricity startlingly higher. Together, the supply crisis and price spikes confirmed that both California and the Pacific Northwest need to take measures to mitigate extreme price volatility and assure sufficient electricity supplies.

Until the 2000 crisis almost all Washington consumers were insulated from short-term market volatility. The extreme price volatility affected only the few industrial customers who had to buy their power on the market or at prices indexed to the market. However, many of Washington's utilities lost money over the summer as they engaged in their usual business of buying and selling power to balance their loads and perhaps make some money. Utilities that lost money either have or will attempt to recover those losses from their customers. At the end of 2000, however, the tightness and volatility in the Westcoast electricity market, coupled with a tight and volatile natural gas market, was having an effect on all electricity consumers. BPA's initial rate increase is due primarily to having to make greatly increased purchases in a rising market. If prices do not moderate, BPA will have to invoke the Cost Recovery Adjustment Clause again and again in order to recover the costs for the purchases it must make to meet rising Northwest demand.

For BPA, by far the region's largest provider of wholesale power and the largest player on the wholesale power market, the summer of 2000 represented close calls both electrically and politically. BPA was repeatedly called upon by the California Independent System Operator (ISO) to step in when California was faced with a Stage Three Emergency (rolling blackouts). This meant that in order to prevent rolling blackouts in California, BPA had to curtail loads in the Northwest and risk violating fish-recovery protocols for operating the Columbia River system. Because BPA had to sell power into the ISO under the ISO cap rather than engage in bilateral trades that private generators and power brokers were free to engage in, BPA was unable to recover all of its own costs for buying power to meet Northwest loads. Despite its forbearance, BPA has been excoriated as a profiteer by many California elected officials who also want BPA to sell power to California public entities on the same basis as it sells power to Northwest public customers. Senators Feinstein and Boxer, along with Representative George Miller, wrote to Secretary of Energy Richardson asking him to stop BPA from signing subscription contracts until issues of regional preference could be decided. This would have, in effect, put subscription on hold indefinitely while Congress attempted to change federal law.

Washington's entire congressional delegation, as well as Governor Locke, defended BPA by writing to Secretary Richardson asking him to reject the requests from California and by directly writing to California members of congress. All other members from the Northwest also signed the letters from the delegation. The Secretary did not delay subscription and BPA informally told its California public customers such as the Bay Area Rapid Transit District that it will not recall power under contract to them.

There is another issue, the future of the DC intertie, that may strain California/BPA relationships. The Los Angeles Department of Water and Power and Southern California Edison have asked the BPA's Transmission Business Line to commit to maintaining its end of the interties at the current 3100 MW capacity for the next 30 years. BPA's cost study indicates that it is not cost effective to BPA at current transmission rates to maintain the intertie, but it would be if southern California customers were charged more. BPA is conducting a public review of this issue and decision is expected in a few months.

The December 2000 energy emergencies once again highlighted BPA's central role in the Northwest electricity picture. BPA's fore-casters lead the decision to declare a Regional Energy Warning on December 8 since they would not be able to meet BPA's loads and respond to California without once again technically violating the Biological Opinion (Bi-Op), regarding Columbia River flows. Rather than importing power to serve Northwest (and especially Washington) loads, as is customary in the winter, BPA was directed by Secretary Richardson to exchange power with California in order to prevent more Stage Three Emergencies in that state. In effect, rate-payers in the Northwest are beginning to pay for the unstable power situation in California through the diversion of BPA resources to California and because California's situation pushes the West Coast wholesale market so much higher which, in turn, forces BPA to pay much more for the power purchases it has to make in order to meet load.

Fish/power Issues

According to the *Draft Fourth Northwest Conservation and Electric Power Plan 1996*, "the total reduction in firm energy generating capability of the hydroelectric system since the Council adopted its first fish and wildlife program amounts to approximately 1,200 average megawatts, representing a 10% loss."[6] The recent draft Bi-Op, published by the Federal Caucus in July 2000, proposes a smaller but still significant further reduction, especially in the winter, when regional power shortfalls are already feared.[7] The draft Bi-Op leaves on the table the option of breaching the four lower Snake River dams, but only if other measures are not successful in recovering salmon. Breaching the dams would reduce the output of the hydro system by 800-1,000 aMW or 4-5%, of regional electricity needs. Finally, during this past summer's power emergencies in California, the California ISO appealed to BPA to provide more electricity than BPA had available under the current Bi-Op. If the California situation had become dire enough that BPA had to meet the request, BPA would have been forced to violate the Bi-Op by operating the river for power rather than fish. This did not happen, but it became clear that fish recovery in the Northwest is subject to the effects of the California power market, a fact reaffirmed during the December 2000 power emergency.

Washington's policy on these issues has been led by the Governor's Salmon Recovery Office which has strenuously argued for salmon recovery options that do not breach dams and for responses to California energy emergencies that do not undercut salmon recovery efforts in Washington and the Northwest.

Transmission/RTO

BPA has voluntarily begun to comply with provisions of the 1992 Energy Policy Act and the FERC orders implementing the act by agreeing to separate its Transmission Business Line from its Power Business Line and filing a proposal with FERC to form a Regional Transmission Organization with public and private utilities in the Northwest. Since BPA is the dominant owner of transmission in the region, its decision may have large effects on all consumers of electricity. These issues are fully discussed in Section B of this chapter.

Threats to BPA/Preference

The great advantage to Washington and the rest of the Pacific Northwest of having BPA as its largest supplier of electricity has not gone unnoticed. From the start, the Federal Columbia River Power System was opposed by many in Congress on ideological and regional lines. Currently the Northeast-Midwest coalition has argued that federal subsidy of the BPA system allows Northwest industry to compete unfairly against their own. Northeast-Midwest coalition members have repeatedly introduced legislation to require that BPA (and other federal power marketing agencies) sell their power at market prices rather than at cost as they are currently required by law. Depending on the market price of electricity, such a change could cost Washington consumers up to $1 billion annually.[8] Because of the summer electricity crises, important California congressional delegation members have demanded that California get access to the BPA system on the same basis as Northwest consumers by repealing regional preference.[9]

In addition to threats coming from outside the region, there has always been controversy within the region over some of the core features of the federal legislation authorizing BPA. These controversies exist because the benefits of the system are not, and have never been, distributed equally across the region. Thus, investor owned utilities and their customers have never liked public preference (dating from the original Bonneville Project Act of 1937), the consumer owned utilities have never liked the residential exchange (passed as part of the Northwest Power Planning and Conservation Act of 1980), while both investor and consumer owned utilities have not liked the requirement to sell power to the Direct Service Industries (updated in 1980 but expiring in 2001). Finally, the four states in the region have often disagreed about whether they are getting fair shares of the benefits of the system, perceptions of fairness being driven generally by whether the state is predominantly public or private power, and the number and importance of aluminum smelters. Historical differences among the states have been compounded by restructuring legislation in Oregon and especially Montana which is changing the concept of what a utility is and thus challenging BPA's long-standing rules about what entities it can sell power to.

Interstate discord intensified during the long subscription and ratemaking processes because these are the vehicles for how benefits are distributed among customer groups and states. Governor Kitzhaber of Oregon made an important speech on September 17, 1999, at the Seattle City Club where he called for "a new governance structure for the Columbia Basin to replace the Northwest Power Planning Council." The speech encouraged both legislators in Oregon and elsewhere and a consortium of IOU's, aluminum companies, and industrial customers generally to begin discussions about how to restructure the governance of BPA. These ideas were circulated and discussed widely under the general rubric of "regionalization" and became a permanent agenda item of the Legislative Council on River Governance, which legislators from the four Northwest states created in order to have a voice in regional discussions that tend to be dominated by the executives branches of their respective states.

The idea behind regionalization is that authority over the Columbia River Power System could somehow be devolved from the federal level to the regional level, thus enabling the Northwest to secure the benefits of the system. Washington State (along with Idaho) has been very skeptical about these ideas. We have argued that first, benefits are already distributed relatively fairly by state, second, distribution among customer classes has already been changed dramatically under subscription, third, it is absurd to ask the same interests in Congress who are trying to take the benefits of BPA away from the Northwest to permanently grant them to us, and fourth, that these efforts do more to divide the region than bring it together.

With Idaho and Washington generally skeptical about making large-scale changes in the governance of BPA, it is unclear whether momentum for regionalization can be maintained. As BPA subscription and rate-making reach their conclusions, some of the urgency for re-thinking BPA governance has diminished. However, BPA promised that after subscription concluded it would be interested in participating in discussions about whether any of BPA's organic statutes should be amended and whatever unhappiness stemming from subscription will lead long-standing critics of the status quo to continue their efforts to change the system. We can be sure that public preference will continue to be under attack, both in the region and nationally, and Washington State will continue to struggle to balance the interests of the approximately 55% of its electricity customers who are clients of consumer owned utilities with the interests of the remaining 45% who are served by investor owned utilities.

We can also be sure that external threats will remain. Even though some persistent critics of federal power marketing agencies were defeated in the recent election, the regional interests and ideological viewpoints they represent will remain. Although national electricity restructuring legislation remains stalled—and the apparent failure in California may keep it stalled—there is still considerable momentum for it. The Northwest needs to remain wary since national restructuring legislation is an obvious vehicle to address the issue of federal agencies selling power to preference customers at cost, while everyone else is becoming subject to market forces. Preserving the benefits of the BPA system for the Pacific Northwest is a continuing challenge.

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[1] The Final Report of the Comprehensive Review of the Northwest Energy System is available at the Northwest Power Planning Council's website at http://www.nwppc.org/crfinal.htm

[2] These documents can be found at the Bonneville Power Administration Power Business Line web site at http://www.bpa.gov/power/p/pblspl.shtml

[3] Source of Fig.2: Bonneville Power Administration, 1999. BPA staff is updating this graph to reflect changes in western wholesale energy markets and BPA's increased need to purchase power in those markets.

[4] The Northwest Power Planning Act (1980), U.S. Code, Title 16, secs. 839(c) and (e) requires that BPA determine the "requirements" of utilities to which it sells power. BPA makes a calculation in which it determines what other resources the utility possesses to meet its loads. Whatever it lacks then constitutes its BPA requirements. Publicly or consumer owned utilities that have no resources of their own are therefore "full requirements" customers.

[5] The work of the Regional Technical Forum (RTF), including its final report on cost-effective measures for BPA's Conservation and Renewables Discount, can be found on the Northwest Power Planning Council's website at http://www.nwppc.org/rtf_toc.htm

[6] *Draft Fourth Northwest Conservation and Electric Power Plan*, (Northwest Power Planning Council, Portland, 1996), p. 4-6. This publication is also available on the Council's website at http://www.nwppc.org/plan/httoc.htm

[7] The Draft Biological Opinion can be found at the National Marine Fisheries Service website, http://www.nwr.noaa.gov/1hydrop/hydroweb/fedrec.htm#NMFS%20Hydro, although navigating the document is difficult. The assessment of the effects electricity generation were obtained from meetings and conversations with BPA and other personnel.

[8] Estimates by Washington State Energy Policy and Utilities and Transportation Commission staff.

[9] Regional Preference was enacted into law in the Regional Preference Act of 1964 and codified at Title 16, United States Code, Sec. 837. It requires that public customers in the Pacific Northwest have the right of first refusal to BPA power and that power sold outside of the region can be recalled by BPA if it is needed in the region.

Section D
Managing Washington's Demand for Electricity

Introduction

Washington State citizens and lawmakers have a strong history of statutorily supporting the efficient use of energy. As early as 1931 the first citizen initiative set forth the purpose of public utility districts to "conserve the water and power resources of the state of Washington for the benefit of the people thereof," (RCW 54.04.020). Since then, energy efficiency and conservation were similarly identified as policy objectives for a variety of local and state government entities. Least-cost planning statutes directed investor-owned utilities to serve customers at the lowest total cost; this typically placed energy efficiency as the top priority resource to be captured. However, the implementation of these policies has a mixed track record in Washington.

Electricity price increases in the early 1980s, and the passage of the 1980 Pacific Northwest Electric Power Planning and Conservation Act began an era of increasingly aggressive pursuit of managing the demand on our existing hydropower-based electricity system through energy efficiency. Beginning in 1979, the Bonneville Power Administration (BPA) led the region in implementing a wide variety of energy efficiency programs. By 1995, the region had saved over seven million megawatt-hours (MWh) of electricity, enough to displace the annual output of two 400-megawatt (MW) generators, and nearly enough to power Seattle.[1] Electricity ratepayers reaped the benefits through lower rates, because saving electricity cost less than building new generation. The environmental savings were also substantial because the resource of choice until the early 1990s was coal-fired power plants.

In the early to mid 1990s, this aggressive pursuit of energy efficiency stopped. The federal Energy Policy Act passed in 1992. This broadened the scope of competition in the wholesale electricity markets and permitted states to implement competition in retail electricity markets. While wholesale electricity markets were developing, the price for natural gas dropped. Power developers chose more efficient combined cycle turbines as their preferred generator, fueled with relatively inexpensive natural gas. Availability of some low-cost power supplies instigated a clamor by industries to restructure the electricity industry to competitive retail markets and abandon resource planning. Utilities were frequently concerned about continuing to invest in customers that may leave their system in the near future. The utility industry response in Washington was, with notable and rare exception, to immediately cut back or eliminate investments in cost-effective energy efficiency, while also discontinuing construction of any new generation facilities. Specifically, investments in efficiency in Washington State dropped by over 70% between 1993 and 1997.[2]

Meanwhile, the state legislature has not heard an electric industry restructuring bill since 1997, the Washington Utilities and Transportation Commission has never pursued restructuring through regulatory procedures, and the forecasts for natural gas prices have risen. Recent electricity supply constraints and price spikes are causing outcries in some states, such as California, to reinvigorate utility investments of ratepayer funds in energy efficiency as a strategic line of defense against rising wholesale electricity prices and constrained transmission and distribution systems. As well, there is a call to invest funds in load management programs and support construction of new generation – including renewable resources.

Additionally, the electricity demand in the Northwest is beginning to outstrip the ability of the current system to supply it. Historically, the Northwest could rely on its vast hydropower system to always provide another MWh of electricity in response to need. But after decades of economic growth in the

Northwest, with few new resources being added to the system in the last five years, the ability of the hydro system to meet peak system loads is increasingly uncertain. Many Washington utilities now buy those last increments of electricity in a very volatile spot market.

Some regions of the country have years of experience implementing programs to manage peak periods of consumer demand for electricity because those regions have been capacity constrained for decades. This concept of managing peak consumer demand for the purpose of effectively utilizing generation supplies, transmission and distribution systems, enhancing system reliability, and for minimizing power price spikes is relatively new to the Northwest. There are a variety of approaches and technologies available to utilities to manage consumer demand for electricity instead of building expensive and infrequently used generators to meet peak loads.

Facing capacity constraints is a new experience in Washington. Facing rising power costs is not new; it is reminiscent of the early 1980s. These challenges demand new policy responses if we are to continue to be able to offer affordable and reliable power to Washington's citizens and businesses. This section of Chapter 1 explores the opportunities for managing consumer electricity consumption with cost-effective energy efficiency and peak load reduction programs. Such efforts can extend the life of our low-cost power system, avoid constructing expensive power generators that are designed to only meet infrequent peak demands, and avoid subjecting our residents and businesses to unmanageable volatile power prices.

There are multiple policy implications to consider in pursuing different paths to address our capacity constrained system and our growing hunger for energy. Key issues to consider are costs and risks. In the broadest sense, who pays the costs, bears the risks, or benefits from the opportunities associated with volatile electricity markets? We may need to develop a comprehensive solution to this question in order to answer the more explicit questions related to demand management programs. Who should pay the costs of programs to reduce energy demand? Should ratepayers bear the costs and risks of volatile wholesale electricity markets if utilities do not actively pursue energy efficiency and load management programs? Who should bear the risk that the program may prove to be unnecessary or too expensive? Who receives the benefits of a successful program? As a statewide community we may want to pursue the path that will most likely provide lower cost energy services at the least risk to consumers, to reliability of the electricity grid, and to the environment.

This section of Chapter 1 includes three subsections describing ways to manage Washington's demand for electricity; Energy Efficiency, Load Management; and Strategies for Managing Peak Loads.

The Energy Efficiency subsection describes the benefits and the costs of achieving electricity consumption reductions by using electricity more efficiently. It reviews past and current achievements by Washington utilities in saving electricity and the potential to cost-effectively double our current savings. It also describes success of the four-year old Northwest Energy Efficiency Alliance (NEEA) as it brings energy efficient products and services to the Northwest.

The Load Management subsection describes consumer load patterns in the Northwest, provides a brief overview of the Western power market's influence on Washington's wholesale power prices, and examines the potential cost of and reliability benefits from managing peak loads.

The final subsection, Strategies for Managing Peak Loads, offers a description of legislation and programs that various states, utilities, or energy service providers are implementing for the purpose of reducing peak loads.

There is significant potential for managing Washington's electricity consumption through improvements in the efficient use of electricity and by implementing effective peak load management programs. However, there are very few policies in place to ensure these investments are made.

Energy Efficiency

Managing electricity consumption focuses on consumers, or on the demand side of the supply and demand equation. There are many methods to manage consumer demand for electricity. The fundamental approach, with which the Northwest energy industry has much experience, is by improving the efficiency of our energy use. Using energy more *efficiently* means getting the same or more useful work while using less energy. It means that consumers can preserve or enhance their lifestyles and industries can preserve or enhance their production figures, all while paying less for energy.

Using electricity more efficiently achieves three primary objectives.

- Economic savings. Using less electricity saves consumers money. It also extends the life of our generation supplies and transmission and distribution systems by reducing the demands on them and postponing needed investments in new equipment.
- Environmental protection. Reducing consumption of electricity reduces generation of electricity. Although our region is heavily dependent on hydroelectricity, the marginal resource is almost always a fossil fuel power plant, most likely coal or natural gas. This means that each MWh saved displaces between 800 and 2500 pounds of carbon dioxide (CO_2) emissions while reducing emissions of air toxins like sulfur dioxide (SO_2), oxides of nitrogen (NO_x), and mercury.
- Enhanced reliability of the electricity grid.

Efficiency measures can range from unplugging unnecessary light bulbs in vending machines, to modifying industrial processes, to designing commercial buildings that use less electricity while providing improved lighting quality, to introducing energy efficient motors to the marketplace. In the past, least cost planning[3] was a key driver for investing ratepayer funds in energy efficiency. Simply put, it is cheaper to save electricity through efficiency improvements than to construct new generation and expand existing distribution and transmission systems.

Electric utilities and the energy services industry in the state have over two decades of experience capturing cost-effective energy savings for consumers. Some of this ability to use energy more efficiently is evident in statewide data for residential energy consumption. Despite a 22% increase in the average size of a new home (by 400 square feet since 1986[4]), and huge increases in the number of household computers and other electricity-gobbling home electronics, the average household energy consumption in the state has remained flat over the last decade.[5] While many factors contribute to this, developments like instituting the Washington State Energy Code, improvements in efficient window technologies, and the array of energy efficient appliances and compact fluorescent light bulbs are key contributors.

Such developments as the increase in use of telecommunication devices, computers and electronic appliances; the growth in commercial development; and the overall growth in the state present a challenge to Washington's energy planners. Washington's electricity consumption has increased by 9% between 1990 and 1999. We can meet some or the vast majority of this growth with an increase in energy efficiency.

The *Washington State Electricity System Study*[6]*,* developed for the 1999 Legislature, documented a dramatic 73% reduction in collective utility investments in energy efficiency programs from 1993 to 1998. Funding levels dropped from $155 million in 1993 to $42 million in 1998. The two primary causes of the drop in both investment and savings achievement in the mid- to late 1990s were; impending restructuring legislation and the accompanying uncertainty as to what treatment utility investments in efficiency would receive in a restructured industry; and the drop in the avoided cost of power.

The tide has turned on both of those issues. The price of purchasing power has been increasing over the last year and restructuring legislation has not had a hearing in Washington's legislature since 1997. That said, stakeholders still watch the national trend toward electricity restructuring and await resolution of the issue in Washington State. Stories of electricity price spikes and higher natural gas prices regularly appear in the media. These same forces that seem to discourage further consideration of restructuring serve to highlight the need for delivering electricity services more energy efficiently.

The tide has not turned quite so dramatically for investments in energy efficiency. Data for the six largest utilities in the state and BPA indicate that investments in energy efficiency have shrunk beyond the 1998 low to $37 million in 1999 and $39 million in 2000. (Over 40% of this investment reflects the work of Seattle City Light which represents 18% of this load.) Investments are projected to rise to $46 million in 2001. Still, this is less than one-third of the 1993 investments. Savings from utility, ratepayer-funded programs are expected to increase from approximately 17 aMW in 1999 to a projected 23 aMW in 2001. (See Table 1.)

Data on electricity efficiency investments for the last three years include half of BPA's past annual investment of approximately $10 million in the NEEA. (This is less than one-tenth of the investment that BPA was making in energy efficiency just in Washington in the mid-1990s.) Additionally, BPA will begin to implement its Conservation and Renewables Rate Discount program in October 2001. The intent of this BPA program is to provide a rate discount for its utility customers who invest in energy efficiency or purchase renewable resources for their customers. This program may leverage an additional 7-8 aMW of savings by Washington utilities in 2002.[7]

The state also has a role in capturing energy savings. For example, the state can adopt procurement guidelines that require agencies and universities to purchase cost-effective energy efficient products and to construct and lease energy efficient buildings. The state can direct resources to the Department of General Administration, which has a very small staff that focuses specifically on delivering energy efficiency assistance to public facility operators at agencies, schools, and community colleges. The state could remedy its energy code amendment process that is failing to capture cost-effective improvements that have been made in building products over the last 8 to 10 years. These improvements are not cutting-edge practices; frequently they are a common construction practice that is simply not reflected in code, and therefore is not captured in all new buildings. For example, updating just the residential window efficiency standard to reflect construction that is current practice throughout most of the Northwest and all of Oregon would save the new homeowner an average of $70 per year in energy bills and would reduce natural gas consumption in the state by 476 thousand therms per year.[8] These are remarkably low-cost savings that the state is not capturing with its current code amendment process.

Politically, consumer interest exists even in rural, conservative parts of the country to support investments in energy efficiency[9]. Economically, a vast resource of cost-effective electricity savings is still available in Washington. This is most readily evident by comparing annual achievement of electricity savings in the state to the Northwest Power Planning Council's assessment of available potential. Seattle City Light, with the most

Year	1992	1993	1994	1995	1996	1997	1998	1999	2000P	2001P
Budget (millions)	$138	$155	$126	$95	$77	$44	$43	$37	$39	$46
Savings (aMW)	70	100	81	N/A	N/A	N/A	N/A	17.7	19.8	22.6

P-Projected

Table 1 Electricity Efficiency Investments and Savings in Washington[10] aggressive energy efficiency plan of any utility in the state, is pursuing a strategy to cost-effectively double its electricity savings achievement. The potential exists for other utilities to achieve similar goals. While Seattle is currently capturing at least seven-tenths of 1% of its load in savings, preliminary indications are that the state's other large utilities are capturing significantly less of their load in savings. In January of 2001, the Northwest Power Planning Council begins to produce a new power plan that will provide an updated resource plan with the electricity savings potential available in the Northwest. Their goal is to complete a draft by January 2002. While this efficiency resource is not boundless, neither is it being fully utilized.

Report on NEEA

In October of 1996, NEEA was jointly funded by the Northwest's investor-owned electric utilities and BPA. NEEA was the first non-profit of its kind nationally with a mission to catalyze its regional marketplace to embrace energy-efficient products and services. NEEA forecasts that its first three years of programs will reduce annual electricity consumption in 2010 by 410 aMW at a total cost to the region of 2.3 ¢ per killowatt hour (kWh).[11] This is enough electricity to offset the construction of more than one natural gas power plant. If all the resource savings – electricity, water, natural gas, etc. – are included in the calculation of benefits, then the electricity saved cost the region less than 1¢ per kWh. This is one-third the cost of new generation. Initially funded for a three-year trial period, NEEA has proven to be successful beyond expectations and is now a model that other regions in the country seek to replicate.

This past spring of 2000, Governor Locke was joined by Governor Kitzhaber, BPA's Administrator, public and private utility executives, and energy stakeholders from Oregon and Washington to celebrate a new funding commitment of $20 million annually for the next five years to the Northwest's Alliance. The setting for this celebration was Siemens Solar Industries' manufacturing plant in Vancouver, Washington, a case study of NEEA's success.

Case Study: Siemens Solar Industries, Vancouver, WA.

Siemens Solar Industries is one of the world's leading makers of solar cells. NEEA provided matching funds to Siemens to implement a project to reduce the electricity used in the energy-intensive process of melting silicon crystals to grow silicon ingots - key components of both solar panels and computer microchips. The near-term goal was to save electricity in this facility and verify the savings due to modifying the furnace technology. NEEA's long-term goal was to demonstrate the success of the furnaces to the ever-expanding microelectronics industry with the goal of having the wafer manufacturers adopt the technology.

Siemens Solar's Vice President shared project results in Vancouver which proved to be great for business, great for the environment, and very helpful in reducing electricity distribution constraints in Clark PUDs industrial service territory. The NEEA-Siemens project reduced power consumption by 51% and Argon gas consumption by 85% for each kilogram of ingot produced, and increased useful ingot yield by more than 20%. Further, the solar cells made with the new silicon ingots produce 5% more electricity than their predecessors, and now cost 5% less. Currently, one wafer manufacturer is testing the furnace modification, and Siemens is expanding its operation in Vancouver.

NEEA's projects are diverse. They include all sectors, and range from bringing front-loading resource efficient clothes washers and a new generation of compact fluorescent bulbs to Washington's retail stores, to increasing the use of variable speed fans in our refrigerated fruit warehouses. Projects also include: financially supporting weather stations that provide essential data to farmers scheduling irrigation; verifying the effectiveness of new technologies that reduce energy consumption at and extend the capacity of sewage waste treatment plants; and assisting the start-up of a Washington company that is introducing new energy efficient motor coupling technologies in the marketplace.

Funding NEEA is a powerful investment in Washington's future as it reduces energy consumption while frequently enhancing, rather than simply maintaining, business practices or lifestyles. NEEA programs will save the Northwest from emitting 1.6 million tons of carbon dioxide by 2010—the equivalent of taking 25,000 cars off the road for good—at costs that are lower than buying market power or building new generation.

Over a 10-year period, NEEA's initial investment of $65 million leverages electricity savings valued at $792 million to the region. Roughly half of these regional savings accrue to Washington's residents, businesses, and industries.

Several of Washington's large public utilities are currently budgeting to provide direct financial support to NEEA later in 2001.

Load Management

Because of our vast system of hydroelectric dams and reservoirs, the Northwest has not historically been capacity constrained. Hydroelectric dams have tremendous peaking capability, which means there is nearly always another kWh of energy available to meet the highest peak demands on the system, and it costs little more to produce that extra kWh. More recently, however, growth in consumer demand and the relatively small amount of new resources developed in the region have shifted the Northwest into an electricity market that is now capacity constrained.

Many regions of the country have faced capacity constraints for decades, and have more experience in operating programs to manage consumer demand for power when the power system has reached its limits. The primary motivations for managing peak periods of consumer power consumption vary. Benefits include avoiding the purchase of power during extreme price spikes, enhancing reliability during periods of extreme weather events, extending the life of existing distribution and transmission systems, postponing the need for constructing new peaking generation, and keeping businesses that are exposed to market prices operating. (In Washington, only some industries, and no households, pay market prices for power.)

There are a variety of terms used to describe managing consumers' electricity consumption and it is useful to clarify a few of them. **Load** refers to the amount of power consumers use; in this subsection, power refers specifically to electricity. **Load demand** is comparable to consumer demand for power. **Peak load** or **peak load demand** refers to a time period – usually hours of a day or a season of the year – when consumers are demanding noticeably more electricity than at other average load periods.

Northwest Load Patterns

Figures 3, 4, and 5 indicate periods of time when Northwest consumers use the greatest amounts of electricity; these are known as peak load periods. Figure 3 shows the seasonal peaks in demand for electricity. December and January are clearly the two months when consumers in the Northwest use the greatest amounts of electricity. The darker bars indicating peak energy demand in a month are taller than the average energy demand each month. The load factor on the right-hand side of the chart is a reference to the percentage difference between peak demand and average demand. The differential between the peaks and the averages are the most extreme in the winter, when as a region we have the lowest load factor. (A high percentage load factor means that the demand for power is fairly constant, such as an industry that is operating seven days a week, 24 hours per day.) This graph indicates that the winter season will place the greatest average demand and the greatest peak demand on Northwest resources.

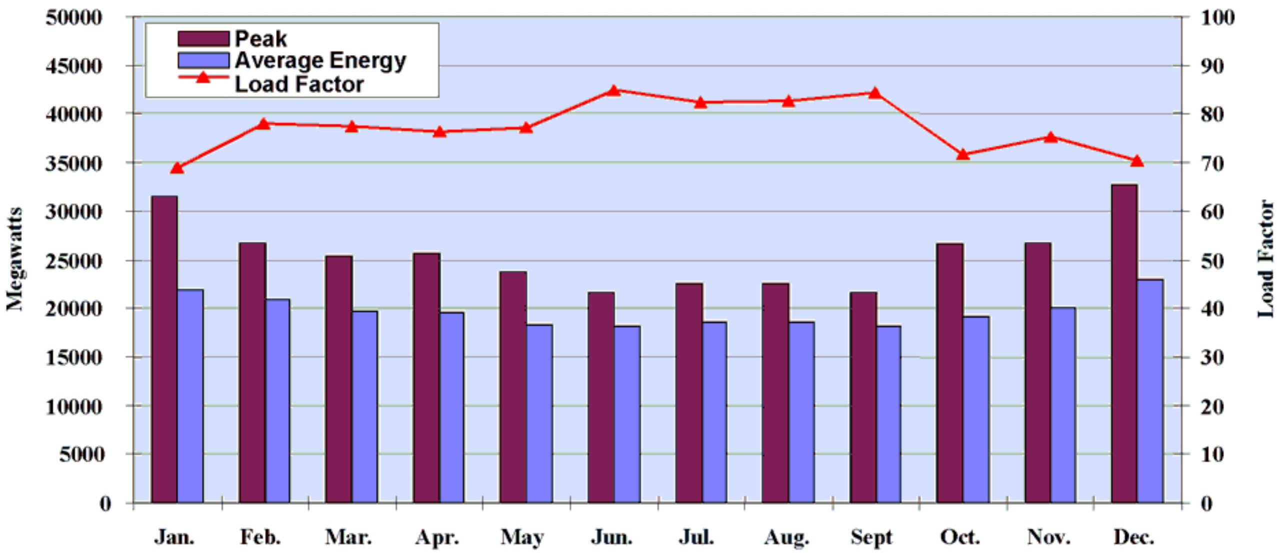

Figure 3 Seasonal Northwest Load Patterns 1995

Source: NWPPC, 4th Northwest Power Plan, Appendix D, Economic and Demand Forecasts, 1996

Peak load management programs aim to reduce the differential between average demands for electricity and peak demands for electricity. Programs may be described as reducing, managing, or shifting loads when demand is the highest. Their intent is to reduce the differential between the dark, peak bars and the average, light bars. Figure 4 provides an average winter day load curve. A winter load management program might target flattening the daily curve at 7 and 8 a.m. and at 6 p.m. In general, load management programs are implemented to reduce peak loads when the value of the savings is the highest.

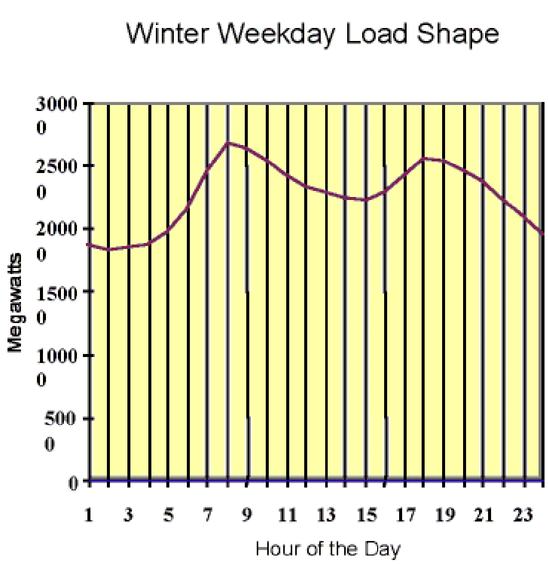

Figure 4

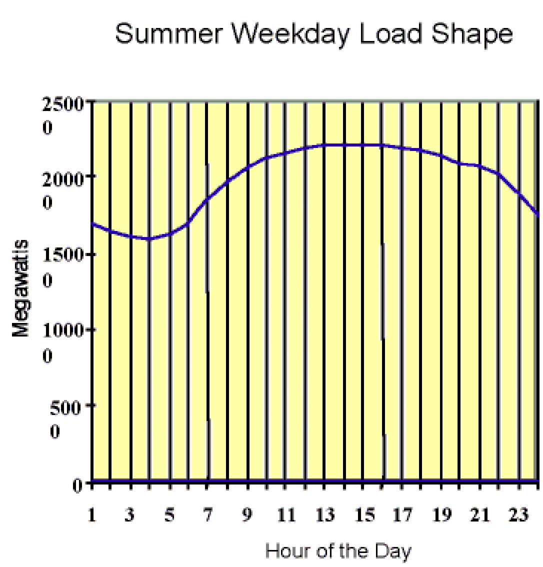

Figure 5

Figures 4 & 5: Typical Winter and Summer Weekday Northwest Load Shapes

Source: NWPPC, 4th Northwest Power Plan, 1996

There is an important distinction between energy efficiency and load management programs. The savings from energy efficiency programs always reduce load. Additionally, energy efficiency measures maintain or even enhance the level of energy service that a customer receives. Peak load management programs either curtail energy use, and thus lower the level of energy service or amenity that the customer was receiving through its electricity consumption, or they typically increase energy use, but shift the consumption to a different, non-peak time of the day or they rely on the use of backup generation. Peak load management programs do not generally achieve any electricity savings. For example, commercial buildings could make large blocks of ice during non-peak evening hours, and then circulate air over these ice blocks in the daytime peak periods to cool the building. In this example, a comparable or large amount of energy is used to provide air conditioning in a commercial building, however the energy used for 'cooling' is consumed at night when it places less strain on the system. In contrast, energy efficiency programs not only reduce load, but also can be designed to save electricity at peak periods of the day or year. For example, energy code improvements that reduce the heating or cooling load for a new residential or commercial building reduce both consumption of electricity and peak demands for power.

Having the ability to manage peak power demands is particularly critical to preserving a reliable electricity grid. Just this December, demand on the electricity system exceeded supply during a cold snap. It is extremely valuable to manage peak demand in the Northwest during periods of high loads driven by extreme weather events that coincide with periods of constrained generation such as poor hydropower conditions or unplanned generator outages. Severe winter peaks are associated with concerns for power outages due to limited power supplies or transmission capacity. Regional stakeholders work collectively on this issue in establishing winter readiness plans. (See Chapter 4.) In these cases, managing weather-driven peaks serves to enhance the electricity system's reliability.

In the absence of load management programs, generation supplies are needed to meet these peak periods of electricity demand. National research shows that in the New England Power Pool, 9% of the generation exists to meet peak loads 1% of the hours during approximately two weeks per year. In Florida, data indicates 15% of the generation is operated to meet peak loads 1% of the time.[12] Reducing the differential between the peaks and the average energy consumed has the benefit of reducing the need to pay for and build rarely used peaking generators.

The market price of power in the Northwest in any given hour is clearly influenced by market events throughout the Western Interconnection, including California. In recent years, extremely high demand during heat waves in California and the Southwest has led to rapid increases in the hourly price for power on the California Power Exchange (PX), sometimes to as high as $750 per MWh (or more than 11 times the highest retail rates for electricity in Washington). These price spike events are both the most expensive times to purchase wholesale electricity, as well as the most lucrative times to sell excess wholesale electricity. Consequently, any electricity saved or unconsumed during these peaks has a higher market value than during other hours of the day or times of year. While Washington utilities have traditionally focused on meeting peak demands during the winter heating season, the dynamics of West Coast power markets mean that demand reduction is most valuable when the power system is most constrained. This may be during extreme weather and generator outage events in the winter or summer. (See Chapter 1, Section A.)

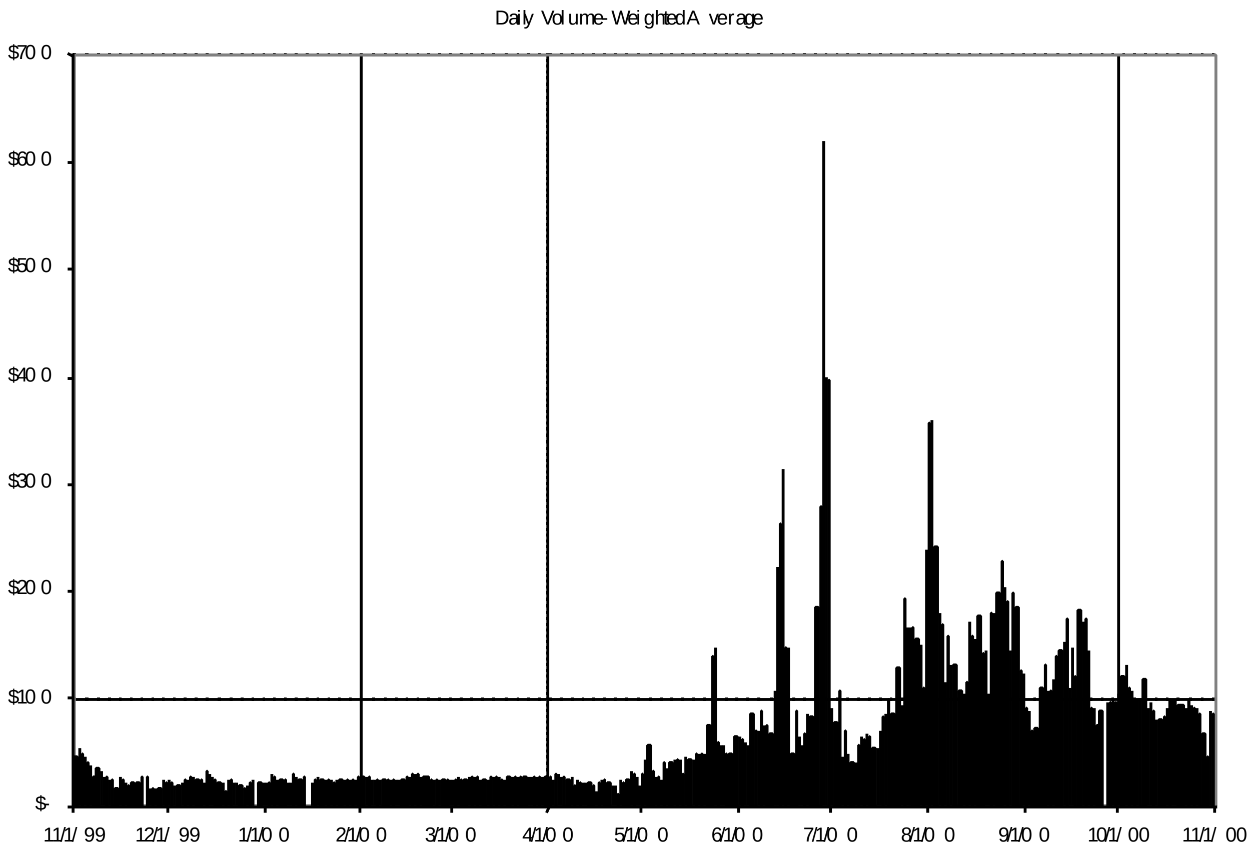

Figure 6 Dow Jones Price Index Power Prices at Mid-C, 11/1/99 - 10/31/00

Source: Dow Jones & Company

Price volatility in wholesale power markets has been especially severe during the second half of 2000. Figures 6 and 7 demonstrate this extreme volatility. Figure 6 presents daily average prices paid for power at the Mid-Columbia (Mid-C) trading hub during a period from November 1999 to October 2000. The Dow Jones Mid-C Index reached a peak of $618 on June 28, about 10 times the highest retail rates in Washington. This December, index prices reached over $4,000 per MWh for much needed power during the cold snap.[13]

Figure 7 presents hourly prices in the day-ahead California PX for an example month of July 2000. There is no hourly market index in the Northwest, but utilities in California are required to purchase the majority of the power they deliver to retail customers in the PX markets, and many companies in the Northwest sell power hourly at prices that are pegged to the PX prices.

Figure 7 gives an indication of the differences in the value of power from one hour to the next. Even during the relatively stable days early in the month, the value of power can vary from $25-30 per MWh during the night to $80-100 per MWh during peak hours in the late afternoon. The last ten days of July saw extreme volatility, with prices frequently approaching the actual $500 cap[14].

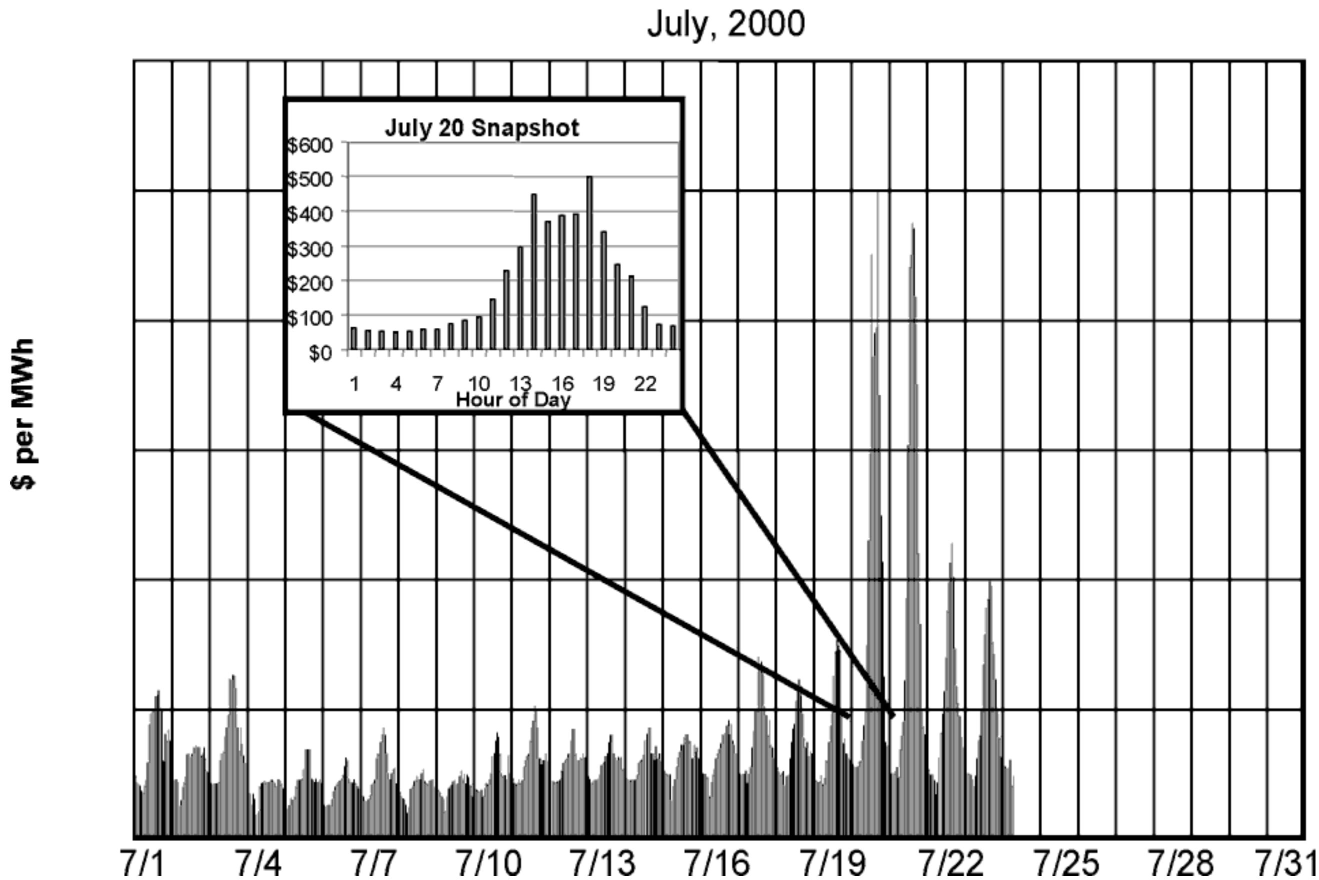

Figure 7 Cal PX Hourly Unconstrained Market Clearing Prices, July 2000

Source: California PX

The trends depicted in these figures contain two lessons for encouraging demand-responsiveness in the Northwest. First, load-management programs will have their highest value during times of extended power supply tightness. Power supplies were short throughout the summer of 2000, which meant that a variety of events such as generator outages that would normally pass unnoticed tended to spark significant price increases. Programs that take a longer-term approach to load management, such as increased energy conservation or backup generation, may be the best way to approach these types of problems. However, the second lesson is that intra-day price differentials may be significant enough to make demand responsiveness val-uable even in relatively less volatile periods: load shifting programs over the course of any single day could have economic value to the customer and to its electricity provider.

A number of programs are being instituted throughout the country that seek to engage retail customers in responding to high market prices during times of peak demand. The section below describes some of these programs and provides an update on what policy-makers are learning from these programs.

Strategies for Managing Peak Loads

Strategies for managing peak loads fall into the following general categories:

1) <u>Direct load control programs</u>: either local utilities or energy service providers implement these programs. The utility or service provider installs control technology in the residence, business, or industry and has the ability to manage a specific load, such as dimming a building's lighting or cycling off a home's water heater, through the control mechanism. The load reduction from these programs is reliable and predictable. Automatic meter readers,

while not mandatory, can verify that the control equipment is functioning and is reducing customers' loads.

2) Interruptible rates: Customers who were willing to exchange lower rates for the possibility of having their utility interrupt or curtail their electricity service in an emergency may have signed up for interruptible electricity rates. These were typically industrial or large institutional customers. Historically, these customers were rarely, if ever interrupted. However, anecdotal information indicates that industries in California were interrupted approximately thirty times over the past year. This December, Puget Sound Energy (PSE) directed schools on interruptible rates in its service territory to reduce electricity con-sumption during the month's cold snap.

3) Bidding for voluntary load shifting: These are newer programs in which a power aggregator or retail energy provider offers to pay large customers to reduce their loads. These are also called power buyback programs. The customer can decide whether the price offered is adequate for them to shed load. These programs have minimum load reduction requirements; e.g., 500 to 1000 kilowatts, and require that customers agree to shed load for a minimum amount of time – typically one hour. As power supplies get tight, these prices get higher.

4) Contracting for voluntary load shifting: This is similar to the program above except that customers sign a contract agreeing to a pre-determined price at which they commit to shed a specified amount of load.

5) Distributed Generation: Operating back-up generation is what frequently permits industrial and large institutional customers to shed load in any peak load management program. Sup-elemental power can feed directly into the grid, or backup generation can enable a consumer to reduce load on their retail energy provider. Most ex-isting backup generation operates on diesel fuel and operating these units results in significant increases in air emissions. Guidelines need to be established in conjunction with air quality authorities to operate backup generation as part of a load man-agement strategy.

Included here is an overview of California's Assembly Bill 970 that includes key provisions to reduce peak electricity load in California and a sample of the types existing of load management programs. Also detailed are load management concepts that integrate smart meters, consumer control technologies, and power pricing strategies that may provide tools in the near future for managing peak loads.

California Assembly Bill 970 (AB 970)

In response to the extreme price events described above, and to general growth in electricity demand accompanied by a lag in construction of generation, the California Assembly enacted and the Governor of California signed AB 970, the *California Energy Security and Reliability Act of 2000*, into law in early September 2000.

"The purpose of this act is to provide a balanced response to the electricity problems facing the state that will result in significant new investments in new and environmentally superior electricity generation, while also making significant new investments in con-servation and demand-side management programs in order to meet the energy needs of the state for the next several years.[15]"

In San Francisco, the immediate costs and risks of electricity price spikes were borne by the utility. In San Diego, consumers bore the risks and price spikes that were immediately averaged into their very unaffordable rates. These events underscored the need for meaningful energy policies regarding real-time pricing, load management, and utilities' roles in each. California's response to these events that threatened the reliability and affordability of their electricity system went beyond "build more generation." It addressed siting policies and the construction of new generation as well as achieving greater electricity savings and operating programs to manage electricity loads.

Among the strategies mandated in AB 970, a budget of $50 million was allocated to state government with an assignment to reduce load demand by 175 to 200 average megawatts (aMW) by June 1, 2001. This is a remarkable statewide effort that will focus particular applications in transmission-constrained San Diego and San Francisco. This one-time load reduction budget is separate from, and in addition to, the funds that the California Assembly directed utilities to invest in energy efficiency, renewable resource development, and low-income weatherization. These separate investments in California's electricity system exceed $200 million annually and have been extended for ten years. This $200 million annual investment also serves to diversify California's power supply with renewables and to reduce electricity consumption through efficiency measures.

The following provides the initial, though flexible, allocation of funds for load reduction that California wants to have in place by June 2001. The majority of the programs focus on shifting power consumption to non-peak periods; the traffic light program reduces load and electricity consumption; and some funds increase the development of renewable resources.

$10 million	Conversion of light-emitting diode (LED) traffic signals.
$10 million	Price responsive heating, ventilation, air-conditioning and lighting systems. The goal here is to leverage the refinement and installation of needed metering and control technologies and software that enable commercial building managers to respond to information on price spikes or energy emergencies that may be sent by the independent system operator.
$10 million	Cool communities: includes painting rooftops white to reflect heat in the peak summer season and planting shade trees.
$5.5 million	Energy efficiency improvements in public universities and other state facilities. This includes improving energy efficiency in these facilities and developing policies and plans that enable public facilities to reduce loads during energy emergencies or energy price spikes.
$5 million	Water and wastewater treatment pump and related equipment retrofits.
$8 million	Development of renewable energy resources for both on-site distributed energy development and for commercial scale projects, and any load reduction strategies that do not fit another category.
$1.5 million	Consulting services as needed.

Dynamic Pricing

The wholesale electricity market faces large swings in prices from hour to hour as described above. Washington's retail consumers do not experience these real-time prices immediately (with the exception of some large industrial customers with market-indexed tariffs or special contracts). Instead, customers pay an average price for power that reflects their utility's strategies for serving load; whether it includes the costs of constructing peaking generators or includes the costs of market power purchases complete with price spikes. The concept of dynamic pricing is to connect the variations in the wholesale price of electricity to those retail customers with the willingness and ability to either self-manage their electricity use or to have their energy service provider manage it for them. Dynamic pricing is most frequently discussed in the context of competitive markets and is a variation of "bidding for voluntary load reductions at market prices" described above. However, there may be applications in regulated markets as well. The goal is to have these customers, representing enough load, respond by shifting or reducing demand for electricity during the periods of extreme demand in order to reduce power prices for all purchasers at that period. Analysis suggests that "a mere 5% market share with a 0.1 elasticity of demand facing spot prices would have reduced a price spike by 40%."[16] Figure 8 demonstrates that, with some exceptions, prices in the California PX day-ahead do not begin to spike until demand reaches some 27,000 MWs.

This does not mean it is useful for all customers to experience market price signals. Most customers may have no ability to manage their loads. In addition, the shape of the electricity supply/price curve is primarily flat in many hours. This means that power prices are steady and provide little incentive or need for consumers to manage load. The value of managing loads is highest during those periods of high consumer demand and constrained supply when the price of power increases rapidly.

San Diego customers were not experiencing dynamic pricing this past summer. The high prices were indeed passed onto the consumers. However, the hourly electricity prices were overlaid with the average load profile of residential consumers to create a monthly bill. Residential customers did not have real-time meters and therefore customers could not benefit by operating electrical equipment at night when demand and prices were lower. The only option consumers had to manage their loads in response to such signals was to turn-off equipment, such as air conditioning for days at a time.

In a well-designed dynamic pricing regime, energy service providers or utilities would negotiate multi-purpose contracts with voluntary customers to purchase electricity for the customer while simultaneously managing the consumer's energy use and operating their load to respond to price signals. For example, the utility or energy service provider may have controls to operate the customer's backup generator, or cycling-off hundreds or thousands of residential hot water heaters for an hour, or increasing the air conditioning thermostat in industrial or commercial buildings.

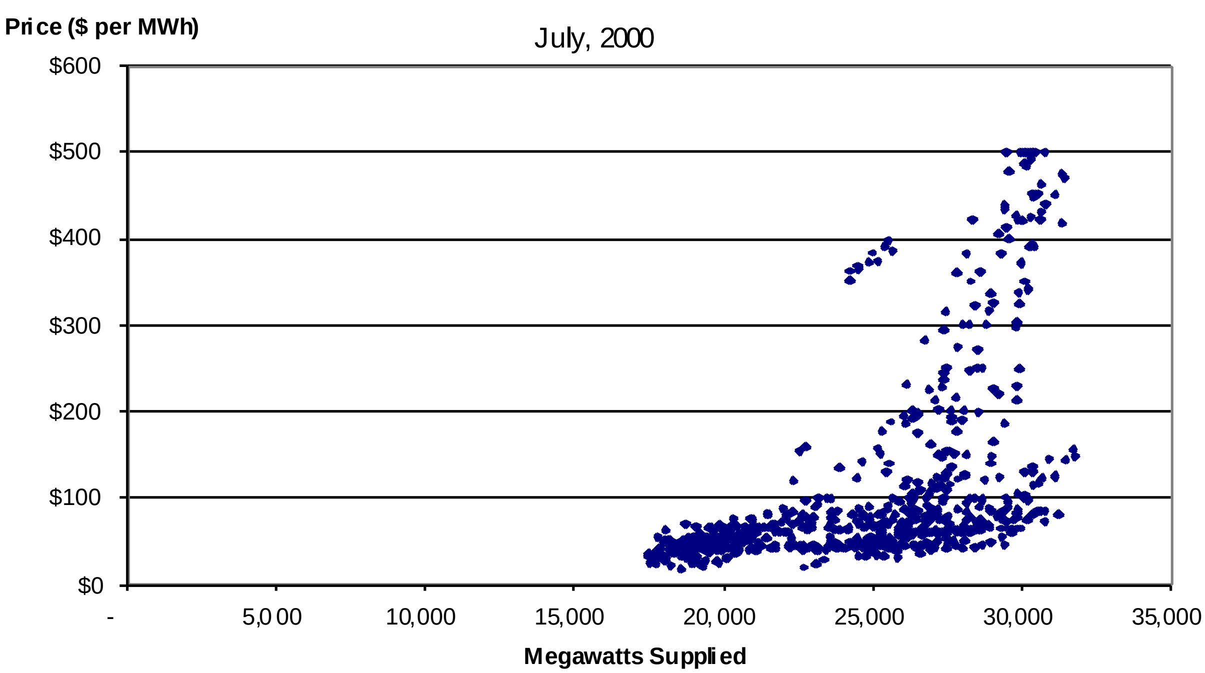

Figure 8 Supply Curve in Cal PX Day-Ahead Market

Source: California PX

Real-time power price signals can create opportunities for consumers to participate in load management programs if the necessary infrastructure exists such as real-time meters (meters that measure electricity consumption instantaneously or every 15 minutes), energy management software, and the appropriate load control technologies. However, real-time pricing may expose customers to market electricity prices without any choice of provider and without the necessary capability to manage their consumption. Participation has to be voluntary to avoid risk-averse customers or customers with little or no ability to respond to real-time prices having to pay volatile electricity prices.

Any use of dynamic pricing, particularly in a monopoly environment should be directed to:

- businesses, industries, or households that either have or can be readily retrofitted with the necessary load control equipment;
- customers that are willing to participate in utility sponsored programs that assist with, provide consultants, or actually manage customer loads and enable the customer to benefit from lower-priced power at non-peak periods;
- customers that provide the electricity system with the greatest peak reduction at the lowest total cost – including installation of control technology.

Participating customers' willingness to respond to prices is influenced by their ability, or that of their energy provider, to intelligently use load management technologies such as control systems, their access to flexible end-use technologies (thermal storage or back-up generation), and their ability to adopt flexible production schedules or to reschedule building operations.[17]

In Washington, where many, but not all, utilities are exposed to spot market prices for only a minority of their power purchases, it may be useful to provide some shared incentive program that encourages a utility to implement load management programs in order to reduce system peak demand and to better utilize existing resources and distribution systems.

Public Appeals to Conserve

In other regions of the country, there are occasionally public appeals to turn off electrical equipment due to the risk of a blackout. These types of public service announcement efforts – frequently communicated over radio stations – have succeeded in temporarily reducing load by as much as 10% according to anecdotal data. The goal of utilities and government agencies is to avoid relying on this tactic repeatedly, but to realize that it is an effective tool for immediate and temporary reduction in electrical load. The Northeast has extensive experience with this public appeal approach.

The Northwest had a rare occasion to use a public appeal campaign during a very serious drought that lasted at least eight months in 1977. Washington and Oregon and their utilities launched a huge public appeal to consumers to reduce energy usage. Governor Dixie Lee Ray turned off the lights in the Capitol Dome as an example, and Oregon banned lighting for outdoor advertising in public rights of way by governor executive order. There were daily reminders to restrict consumption. As a result of this campaign the state's largest electric utility reported a 5% reduction in *total energy* consumed for the *year*. This was not a peak load issue; this was an energy issue as there was little water behind the dams. The savings were not simply capacity savings but total energy savings.

More recently, the request this December by utilities and Washington's Governor to use less electricity during the cold snap reduced short-term demand by approximately 3-4%.

Eugene Water and Electric Board's Response to December 11th Cold Snap

In Oregon, Eugene Water and Electric Board achieved a 14 MW load reduction on December 11, 2000. Based on Energy Information Administration data, that is about 5% of their load. Eugene Electric's industrial key account representatives had been preparing for this type of event and were able to identify, in advance of the cold weather, load shedding or generation backup opportunities with their two to three dozen largest customers. They estimate that half the 14 MW reduction was achieved with the use of customer backup generation and half by load shedding. Eugene Electric paid their customers three-quarters of the market price not to exceed $500 per MWh. By knowing their industries, Eugene's key account representatives could readily identify customers with inefficient generators that normally sat unused, or customers with loads that were "non-critical" in any given day. For example, one plant shut down a huge card-board recycling machine for the day, while one mill shut down two days early to sharpen their blades off-schedule in exchange for the payment.

Eugene Electric also ran a media campaign that asked customers to lower their therm-ostats, turn-off unnecessary appliances, not use Christmas lights until after 8 p.m., and turn their water heaters down to 120 degrees Fahrenheit. They utilized stories in the news, public service announcements, and television news segments.

Bidding Voluntary Load Reduction

BPA's Programs

BPA purchases power from the wholesale market, in which there are periods of price spikes; and yet charges its wholesale and retail preference customers fixed prices for electricity that do not vary as market prices vary. Additionally, there are episodes in the winter when the Northwest is physically con-strained in its ability to meet extreme demands for power. In response to these two factors, BPA is currently recruiting participants to participate in a voluntary load displacement program. Their target is to sign up 300 aMW of load by mid-December, increasing to 800 aMW of load by December 2001.[18]

Participants will be offered the opportunity to bid in an electronic auction to determine the price per kWh at which they will curtail load. Minimally, participants must be able to shed one MW of load for one hour. By early November 2000 BPA had four customers representing approximately 150 MWs of load registered. The participants range from industrial plants located in service territories of BPA's customers, to industries served directly by BPA, to a small Oregon utility prepared to curtail load. The utility has radio-controlled equipment already installed in residences that will allow the utility to cycle off hot water heaters for an hour at a time. Comparable programs are in the design or early implementation phase in a number of regions in the country.

Portland General Electric's Electricity Exchange

Effective July 2000, Portland General Electric initiated its Electricity Exchange Rider Pilot. The goal of the voluntary program was to buy back power from large customers that had the ability to curtail load. The utility sends large customers a one or more day-ahead price signal to which participating customers can choose to respond by reducing at least one MW of load for a minimum of one hour, for up to 16 hours per day. Portland General Electric modified the program slightly in late fall 2000. The utility now has the flexibility to select when to announce a voluntary load-shedding event, rather than announcing one based on a specific California PX price. The utility financially settles with their load-shedding customers by paying half of the California Independent System Operator's real time price for Northern California. This program has proven to be beneficial to Portland General's shareholders and ratepayers. Approximately ten large customers are participating with some regularity.[19] The pro-gram resulted in 150 MW of peak load reduction during events in December 2000.[20]

Puget Sound Energy Load Management Pilots

PSE has replaced nearly one million big, old glass meters with automatic meter readers (AMRs) in their service territory over the past several years. While traditionally meters are read monthly or bimonthly and provide only a total amount of energy consumed during the month, AMRs rely on radio devices to take measurements of consumer energy consumption in real-time. PSE is initiating a pilot program this winter using these meters to track time-of-day electricity consumption for

400,000 residential and commercial customers. Their goal is to see if providing customers with hourly consumption data, overlaid with simplified information on market power prices during four periods of the day, will stimulate customers to voluntarily shift their electricity consumption to another time of day.

Additionally, PSE implemented a small pilot program in 104 homes in Kent during February through April 2000, entitled, "Home Comfort Control Pilot." The purpose was to test the utility's ability to manage load using thermostat setbacks. The majority of the homes were natural gas heated, which are not the real target for near-term electric load management programs. Still, some of the lessons learned were fuel-neutral.

During an 8-10 week period volunteer households experienced 45 random two-hour episodes at which time their thermostats experienced either 2 or 4-degree temperature setbacks. Volunteers could override the setbacks and have full heat if desired. Pilot partners provided or installed programmable thermostats, wireless communication, and energy management software.[21]

The conclusions from the pilot indicate that the two-way communication system performed reliably; 95% of the volunteers would participate again; and 75% indicated a willingness to experience 30 setbacks per year. Incentives to participate in the pilot included a free programmable thermostat and $100.

Utility Load Control Programs

Wisconsin Electric implemented a peak load management program in 1991. The utility installed radio receivers in residences and wired them to the thermostats in order to reduce air conditioning load. This program did not cut off the air conditioning; instead it adjusted the thermostat control by signaling that the house was cooler. The utility could invoke the controls during five to ten days per summer. While they implemented this control technology seven times in 1999, they didn't use it all in the milder summer of 2000. The utility has three program and payment options that include giving a $40 per year customer credit for participating for up to four hours versus a $12 annual credit for allowing the utility to cycle the air conditioner off for 15 minutes every hour. They currently have 25,000 customers participating and can reduce load by 50 MWs. The program was marketed to consumers as a reliability program and is only operated at times of supply constraints, not for the utility to avoid purchasing power during price spikes.[22]

Similar load control programs for a variety of appliances that contribute to peak loads have been in place in the Northeast and Southeast for years. Many of these programs were discontinued as states restructured their electricity industry. These programs need communication and control technology, but do not require real-time meters. Well run load control programs have been favorably well-received by customers. One 1995 study in Grand Rapids, Michigan measured the indoor temperature increase of 200 households participating in a load control program of over 1,000 households, shutting off their air conditioning for up to four hours. The average temperature rise was never greater than 1.8 degrees F. The maximum temperature rise was 2.8 degrees F.[23]

Both the Los Angeles Department of Water and Power and Sacramento Municipal Utility District demonstrated thermostat control programs in their own utility buildings last summer in the hopes of operating full scale programs in the summer of 2001. Los Angeles Power raised the thermostat settings by two degrees between noon and 6 p.m. in two buildings totaling 850,000 square feet. The project was estimated to reduce load by 300 kilowatts and it received almost no complaints from the occupants. Sacramento's demonstration dimmed the lights by 30% and raised the thermostat by four degrees in one of their commercial buildings. They observed an average peak load reduction of 30%. Employees did not report noticing any differences in their work environment. Many variables can effect these results and it is difficult to establish firm savings numbers.[24]

Wisconsin's Electric Dollars for Power & Power Market Incentives

Wisconsin Electric designed two load management programs immediately prior to the summer of 2000. They have not implemented these programs yet due to the mild summer that year. "Dollars for Power" is a voluntary load reduction program. Customer's need a demand meter and the ability to reduce their load by 50 kW. The utility maintains a reference load shape and reimburses the customer when they measure a drop in load, commensurate with their target. Participants can select one of three prices: $.40, $.80, or $1.25 per kWh. When wholesale market prices reach these thresholds, the utility contacts the customer, and the customer sheds load. Some participating customers have backup generation. The utility recruited 100 MWs of load participation from approximately 100 customers.

The "Power Market Incentives" program requires that a customer can minimally shed 500 kilowatts. Wisconsin Electric activates this program the day before they need the customer to shed load. The customer receives 100% of the wholesale market price in exchange for shedding load. Their recruitment experience suggests that large customers will not shed load for less than $300 per MWh.[25]

New England Independent System Operator

Independent System Operators (ISOs) are starting to implement peak load management programs that include operating backup generation and purchasing power capacity. The ISO's primary responsibility is to operate the transmission system and an ancillary service market. In New England, the ISO is testing a pilot program this winter in preparation for full implementation in the summer of 2001. The goal in New England is to maintain the reliability of the regional electricity grid at a lower cost. The New England ISO target is to have 300–600 MWh of load participating in their program that would enable the ISO to communicate via the Internet with the participant and obtain load shedding within ten minutes. The ISO will contract with customer aggregators or local utilities to achieve this load reduction capability. In turn, this will permit the ISO to reduce their Federal Energy Regulatory Commission required "spinning reserves" (their system's power reserves). Additionally, the communication and metering equipment installed for the purpose of enhancing system reliability and lowering the cost of this reliability will also permit these customers to benefit from reducing load during future market-driven price spikes.[26]

The California ISO is currently investigating its opportunities for implementing load management projects.

Smart Meters and Communication Software

Smart meters refer generally to meters that have more technological capabilities than the old glass meters that simply measured kWh energy consumption. This new generation of meters can receive Internet e-mail messages, track instantaneous energy demand, remember the moment of peak demand, track energy consumption in minute or hourly intervals, provide power quality monitoring, provide power outage detection, provide frequent two-way communication between the meter and the power provider, enable a customer to receive real-time prices, and send signals to shed non-critical loads.

This meter technology can be installed to work in cooperation with energy management software and load control technologies to enable consumers or utilities to better manage their load consumption. While the utility sponsored load control programs of the past did not rely on this advanced metering technology, the advent of this technology does create new opportunities for energy service providers and customers to manage energy consumption in response to price spikes or incentive programs to manage system reliability. Some new residential developments are installing electronic control systems for appliances in homes that may lend themselves to load management programs. Many commercial and industrial customers already have energy management systems installed in their buildings; installation of communication software may enable some of these customers to respond to power market signals or incentive programs.

The Swedes are demonstrating a new role for smart meters in the future "smart house." Electrolux Incorporated, a major international appliance manufacturer based in Sweden, is offering 7,000 households on the Swedish island of Gotland free energy- and water-efficient front-loading clothes washers. These homes are wired with smart meters that will count the number of washloads done per household. Electrolux will charge the customers per each washload for the use of the Electrolux clotheswashers. Consumers avoid purchasing a new clothes washer, and Electrolux guarantees service on the equipment, promises to replace the units in 4-5 years or after 1,000 washers, and recoups the price of their product (or more) with their fee per washload. Electrolux is selling clean clothes, not clothes washers. This provides a view into marketing opportunities still to come.

Conclusions

There are extensive and untapped opportunities for using electricity more efficiently in Washington State. Energy efficiency, by reducing demand for electricity, contributes to system reliability, primarily in terms of supply adequacy. Any federal or state utility reliability bill or restructuring bill should include provisions to strengthen rather than allow the continued erosion of funding devoted to energy efficiency programs.[27] Utilities and government need to reinvigorate their efforts to realize these savings. The rewards are increased electricity grid reliability, lower-cost energy services, extended life of existing transmission and distribution systems, lowered reliance on additional natural gas generators, and the reduction of CO_2 emissions into our atmosphere.

Managing our peak loads is an untried tool for many in the Northwest energy community. The benefits of actively exploring and pursuing load management opportunities include increasing the reliability of our power system, reducing electricity wholesale price spikes, avoiding the use of dirty diesel backup generators, and avoiding the cost and construction of generators designed solely as peak power providers.

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1 The Green Book, p. 7, Northwest Power Planning Council. February 1996.

2 Washington State Electricity System Study, Washington Utilities and Transportation Commission, and the Washington Department of Community, Trade and Economic Development p. 9-6, December 1998.

3 WAC 480-100-251. The least cost planning rule adopted by the WUTC in 1987 requires investor-owned electric utilities to evaluate energy efficiency and supply-side investments on an equivalent basis and to select the lowest-cost way of meeting demand.

4 Baylon, David, S. Borrelli, and M. Kennedy, "Baseline Characteristics of the Residential Sector in Idaho, Montana, Oregon and Washington." February 2000.

5 See Chapter 6, figures 9 and 10.

6 Washington State Electricity System Study, Washington Utilities and Transportation Commission, and the Washington Department of Community, Trade and Economic Development, Chapter 9. December, 1998.

7 Savings estimate based on OTED's analysis of reasonably optimistic results of BPA's Conservation and Renewables Rate Discount program if utilities choose to invest heavily in efficiency. Additional information on the rate discount is available on the BPA website, http://www.bpa.gov/Energy/N/C8R.htm

8 Comments submitted by Department of Community, Trade and Economic Development for Code Rulemaking process, 10/12/2000.

9 Roberson, Mark, "What Do Consumers Value: A Report by Central and South West Services Inc., on Deliberative Polls at Central Power and Light, West Texas Utilities, Southwester Electric Power Company." Presented to the National Association of Regulatory Commissioners.

10 Investment data for 1992 through 1998 represents data from fifteen utilities in Washington & BPA collected for 1998 Washington State Electricity System Study. This study did not collect first year savings data from utilities. Savings data for 1992, 1993, and 1994 were collected by the Northwest Power Planning Council for the 1996 Green Book; this reflects data from the state's 6 largest utilities and BPA. All savings data and investment data for 1999 through 2001 represents data from state's six largest utilities & BPA collected for this report. Year 2000 and 2001 data are projected. Investment figures have not been adjusted for inflation. Anecdotal information suggests that smaller utilities are capturing an additional average megawatt of savings in the year 2000.

11 "The 1999 Alliance Cost-Effectiveness and Savings Information."

[12] Analysis by the Regulatory Assistance Project. See http://www.rapmaine.org

[13] www.energyonline.com

[14] The California PX did not have an official price cap, but prices were constrained by the existence of a $500 price cpa in the real-time imbalance market operated by the California Independent System Operator.

[15] Assembly Bill 970, California Energy Security and Reliability Act of 2000, section 2.

[16] Caves, D, K. Eakin, and A. Faruqui, April 2000. *Mitigating Price Spikes in Wholesale Markets through Market-Based Pricing in Retail Markets.* Electricity Journal, Volume 13 Number 3.

[17] Caves, D., K. Eakin, and A. Faruqui, April 2000. *Mitigating Price Spikes in Wholesale Markets*. Electricity Journal Volume13, Number 3.

[18] BPA program brochures and conversation with BPA program manager, John Hairston, October 2000.

[19] Portland General Electric Schedule 86 tariff.

[20] "Power Crunch Prompts IOUs to File Demand Exchange Tariffs," Clearing Up 12/18/2000

[21] Presentation by PSE Vice President P. Gullekson, "Home Comfort Control Pilot and Integrated Technologies." Summer Reliability and Load Management Workshop, Sacramento, CA. October 2000.

[22] See http://www.wisconsinelectric.com.

[23] Reed, John, W. Mok, D. Sumi, and T. Boertman, *Temperature Changes in Residential Dwellings from Direct Control Actions*, American Council for an Energy Efficient Economy 1996 Summer Proceedings.

[24] California Energy Markets November 17, 2000.

[25] November 2000, conversations with staff at Wisconsin Electric: Tim Craft and Don Johnston.

[26] November 2000, conversations with Paul Peterson at New England Independent System Operator.

[27] Cowart, Richard, and N. Reynolds, *The Contribution of Energy Efficiency to the Reliability of the U.S. Electric System,* American Council for an Energy Efficient Economy 2000 Summer Proceedings.

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[27] Cowart, Richard, and N. Reynolds, *The Contribution of Energy Efficiency to the Reliability of the U.S. Electric System,* American Council for an Energy Efficient Economy 2000 Summer Proceedings.

CHAPTER 1 ELECTRICITY

Section E
Meeting New Electricity Needs

Electricity demand in Washington State has been growing at slightly less than 1% annually. Over the next few years, most new demand is likely to be met by three major sources: combined-cycle combustion turbines fueled by natural gas, wind turbines, and energy efficiency measures. Table 2 provides basic cost information on these three technologies as well as others that are likely to see some development over the next several years. The values in Table 2 are estimated costs to produce a kWh of electricity and do not indicate what price a kWh may sell for in the open market.

Although Washington State has not seen the addition of any large new generating facilities (250 MW or more) during the 1990s, there have been a significant number of small and medium-size new plants added in the last decade as well as upgrades and refurbishments of existing hydroelectric and nuclear facilities. Tables 3 and 4 summarize these capacity additions, upgrades, and refurbishments.

Technology	Range of Costs Cents/kWh			Representative Projects	Notes
	Gas Cost: ($ per MMBtu)				
Natural Gas Technologies	Gas @ $3.50 per MMBtu	Gas @ $4.50 per MMBtu	Gas @ $5.50 per MMBtu		
Combined Cycle Combustion Turbine	3.5¢/kWh	4.3¢/kWh	5.0¢/kWh	♦ Chehalis (Tractabel) ♦ Sumas (NESCO)	Source: Sumas Energy 2 Application
Simple Cycle (Peaking) Turbine	5.1¢/kWh	6.3¢/kWh	7.5¢/kWh		Source: NWPPC, 4th Power Plan
Renewable Technologies	Low Estimate	High Estimate			
Wind	3.2¢/kWh	6.5¢/kWh		♦ Stateline (FPL) ♦ Vansycle	Note: Includes 1.7¢/kWh Federal Production Tax Credit
Biomass	2.4¢/kWh	6.3¢/kWh			Source: NWPPC, 4th Power Plan
Solar	23.0¢/kWh	37.5¢/kWh			Source: Western SUN
Geothermal	5.7¢/kWh (Fourmile Hill)	10.4¢/kWh (NWPPC)		♦ Fourmile Hill (BPA/Calpine)	Sources: BPA Press Release, NWPPC 4th Power Plan
Energy Efficiency	0.4¢/kWh	3.0¢/kWh			Source: NWPPC, 4th Power Plan

Table 2 Electricity Supply Options

♦ 2000 average wholesale natural gas price (Sumas hub): $4.93 per MMBtu 2000 average wholesale electricity price (Mid-Columbia hub): 8.8¢/kWh

Project	Technology	Fuel	Installed Capacity (MW)	Peak Capacity (MW)	Average Energy (MWa)	Capital Cost ($Millions)	Completion Date	County
DoubleTree Hotel Fuel Cell	Fuel Cell	Natural Gas	0.2	0.2				Spokane
Spring Creek	Hydroelectric		0		0		Feb-91	Klickitat
Steam Plant No. 2	Steam	Coal/Wood/Refuse		38	32.3		Mar-91	Pierce
Spokane MSW	Steam	Municipal Solid Waste		23	15.3		Mar-91	Spokane
March Point 1	Combined Cycle (Co-Gen)	Refinery/Natural Gas	80		70		Oct-91	Skagit
March Point 2	Combined Cycle (Co-Gen)	Refinery/Natural Gas	60		52.9		Jan-93	Skagit
Sumas Energy	Combined Cycle (Co-Gen)	Natural Gas		125	97		Apr-93	Whatcom
Encogen 1-3	Combined Cycle (Co-Gen)	Natural Gas		160	140.8		Jul-93	Whatcom
Wynoochee	Hydroelectric		10.8	10.8	4.3		Dec-93	Grays Harbor
Tenaska Washington II	Combined Cycle (Co-Gen)	Natural Gas		245	215.6		Apr-94	Whatcom
Black Creek	Hydroelectric		3.7	2	1.6	7.8	May-94	King
Cowlitz Falls	Hydroelectric		70	44	29.2	103.0	Aug-94	Lewis
Longview Fibre-CT	Combustion Turbine (Co-Gen)	Natural Gas	65				Jun-95	Cowlitz
South Fork Tolt River	Hydroelectric		15	15	8.1	28	Nov-95	King
Fort James (Camas)	Boiler/Turbine (Co-Gen)	Various	52	47	40	53	Dec-95	Clark
Kimberly-Clarke	Boiler/Turbine (Co-Gen)	Various	43		37.1	115	Jan-96	Snohomish
Burton Creek	Hydroelectric		0.8		0.4		May-96	Lewis
Avista Corp. Fuel Cell	Fuel Cell	Natural Gas	0.2				Jun-97	Spokane
River Road Generating Project	Combined Cycle	Natural Gas	248		220	127	Dec-97	Clark
North Side	Internal Combustion	Landfill Gas	0.9			1.3	Jun-98	Spokane
Tacoma Landfill	Internal Combustion	Landfill Gas	1.9	1.9	1.8	2.7	Sep-98	Pierce
Roosevelt Landfill	Internal Combustion	Landfill Gas	8.4		8	12.9	May-99	Klickitat
Total			659.9	711.9	974.4	450.7		

Table 3 New Power Plant Additions (1990's)

Source: Northwest Power Planning Council, Database maintained by Jeff King, July 2000.

Project	Technology	Installed Capacity (MW)	Peak Capacity (MW)	Average Energy (MWa)	Capital Cost ($ Millions)	Completion Date	County
Monroe Street Rehabilitation	Hydroelectric	10		7.6		Jul-92	Spokane
WNP-2 Upgrade 1 (Turbine Rotor)	Nuclear		24	16		Jan-93	Benton
Cushman 1 Runner Replacement	Hydroelectric		0	0.4		Sep-93	Mason
Wanapum Rewinds	Hydroelectric			31.3		Dec-93	Grant
LaGrande Runner Replacement	Hydroelectric	0		0.4		Jun-94	Pierce
Nine Mile 3 & 4 Rehabilitation	Hydroelectric	14		13.4	20	Jul-94	Spokane
WNP-2 Upgrade 2	Nuclear		52	36	25	Jun-95	Benton
SCL Energy Management System	Hydroelectric	0		15	22.8	Nov-95	King
Diablo Runner Replacement	Hydroelectric	10		8		Dec-95	Whatcom
George Runner Replacement	Hydroelectric	0		1		Dec-95	Whatcom
Long Lake 1,2,4 Turbine Replacement	Hydroelectric	12		1.2		Sep-96	Lincoln
Cushman 2 Runner Replacement	Hydroelectric		0	0.9		Oct-96	Mason
Cedar Falls Rewind	Hydroelectric	0		0.6		Dec-96	King
McNary Dam Fish Attraction	Hydroelectric	9.9		8	32.7	Nov-97	Benton
Grand Coulee 22-24 Stator Replacement	Hydroelectric	315	315		30	Dec-97	Grant
Ross Runner Replacement	Hydroelectric	0	2.2	2.1		Dec-97	Whatcom
Long Lake 3 Turbine Replacement	Hydroelectric	4	393.2	0.3	1	Dec-00	Lincoln
Total		374.9	786.4	135	131.5		

Table 4 Hydroelectric and Nuclear Refurbishment/Expansion (1990's)

Source: Northwest Power Planning Council, Database maintained by Jeff King, July 2000.

CHAPTER 2 VOLATILITY IN PETROLEUM MARKETS

After a long lull brought about by consistently low prices, recent years have seen renewed attention focused on the oil industry in response to extreme volatility in global oil markets. This focus culminated in President Clinton's decision to release oil from the nation's Strategic Petroleum Reserve in October 1999, and the emergence of oil policy as an issue in the 2000 Presidential campaign. Locally, the impact of higher prices was eclipsed by the tragic explosion of the Olympic Pipeline in Bellingham, but consumers are still paying gasoline prices that are 50% higher than they were just two years ago.

This chapter describes the events that have affected crude oil and gasoline prices faced by Northwest consumers in recent years. It also discusses the supply effects of the Olympic Pipeline explosion and the trend toward mergers of large oil companies and its ramifications for Northwest markets.[1]

Gasoline prices

Gasoline prices began to rise early in 1999. As Figure 9 shows, prices in Washington and nationwide had been declining relatively steadily since May 1996. In fact, the average U.S. gasoline price in 1998 was the lowest of any year in history in inflation-adjusted terms. Washington gasoline prices bottomed out in February of 1999, averaging $1.10 statewide during that month, but jumped by over 30¢ per gallon by April 1999.

Sudden gasoline price increases are not uncommon during that time of year. Inventories tend to be low as refineries are turning their attention from heating oil to gasoline. Temporary shortages can be exacerbated by crude oil prices that are perceived to be unsustainably high; if prices are expected to fall during the next several months, refiners will attempt to avoid building

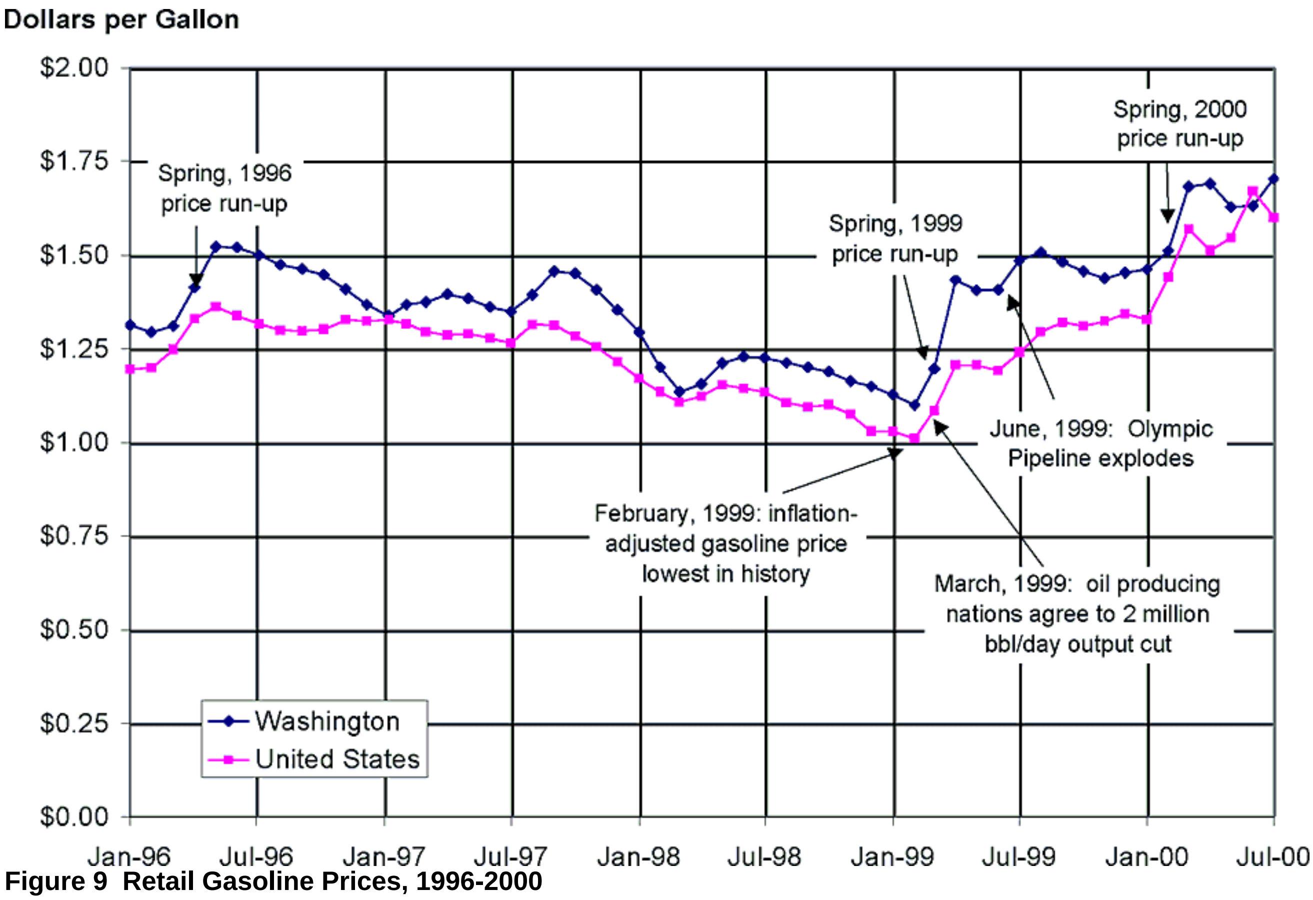

Figure 9 Retail Gasoline Prices, 1996-2000

Source: Energy Information Administration

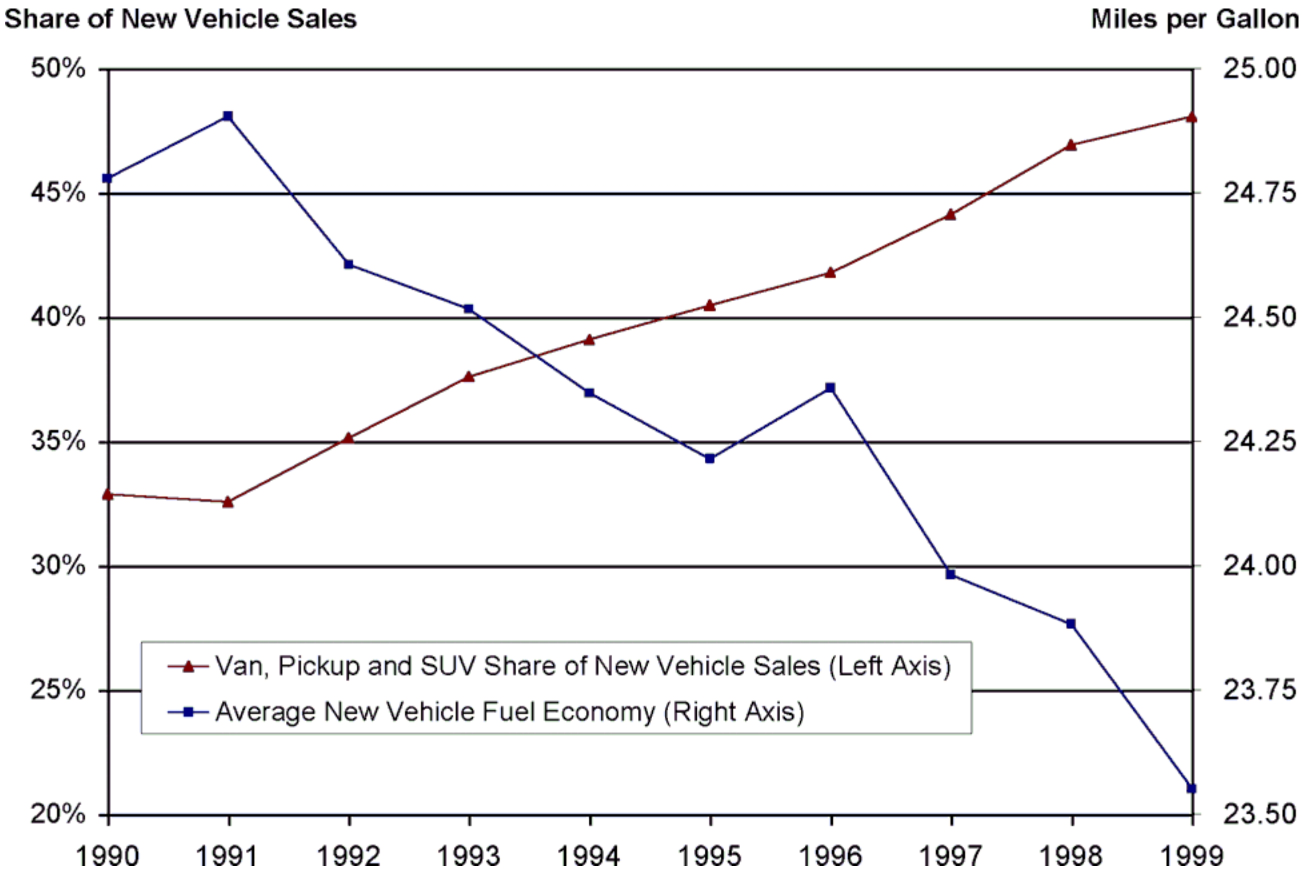

Figure 10 Light Truck Sales and New Vehicle Fuel Economy, 1990-1999

Source: Oak Ridge National Laboratory, Transportation Energy Data Book[2]

their stocks with expensive crude early in the season by purchasing as little as possible. Refining industry problems such as explosions or other forced outages frequently contribute to product shortages, especially in West Coast markets where refining margins are tight. This situation occurred in 1996, 1999, and 2000.

Prices of refined petroleum products in Washington increased further after the June 10, 1999, explosion of the Olympic Pipeline near Bellingham, though the effect appears to be relatively small. The Olympic Pipeline situation is discussed in more detail below.

While the U.S. economy as a whole is less dependent on oil, and hence less susceptible to oil price shocks than it was in the 1970s, American consumers may be more vulnerable at the end of the 1990s century than they have been in years. Low gasoline prices throughout the decade contributed to trends such as longer commutes, lower use of mass transit, and the increased popularity of large, inefficient vehicles such as minivans and sport utility vehicles. And lifestyle decisions like the choice of a vehicle or a home are not easily changed, which means that, in the short term, many Americans are simply stuck paying higher fuel prices. Figure 10 shows how increasing light truck sales in the United States have led to declining new vehicle fuel economies throughout the 1990s.

Crude oil prices

The root cause of higher gasoline prices can be found in the crude oil markets. In 1998, oversupply of crude oil due to recession in East Asia led to record-low crude oil prices. Oil-producing nations responded by announcing in March of 1999 that they had agreed to a two million barrel per day cut in output, reducing global crude supply by some 5%. This marked the first time in over a decade that the Organization of Petroleum

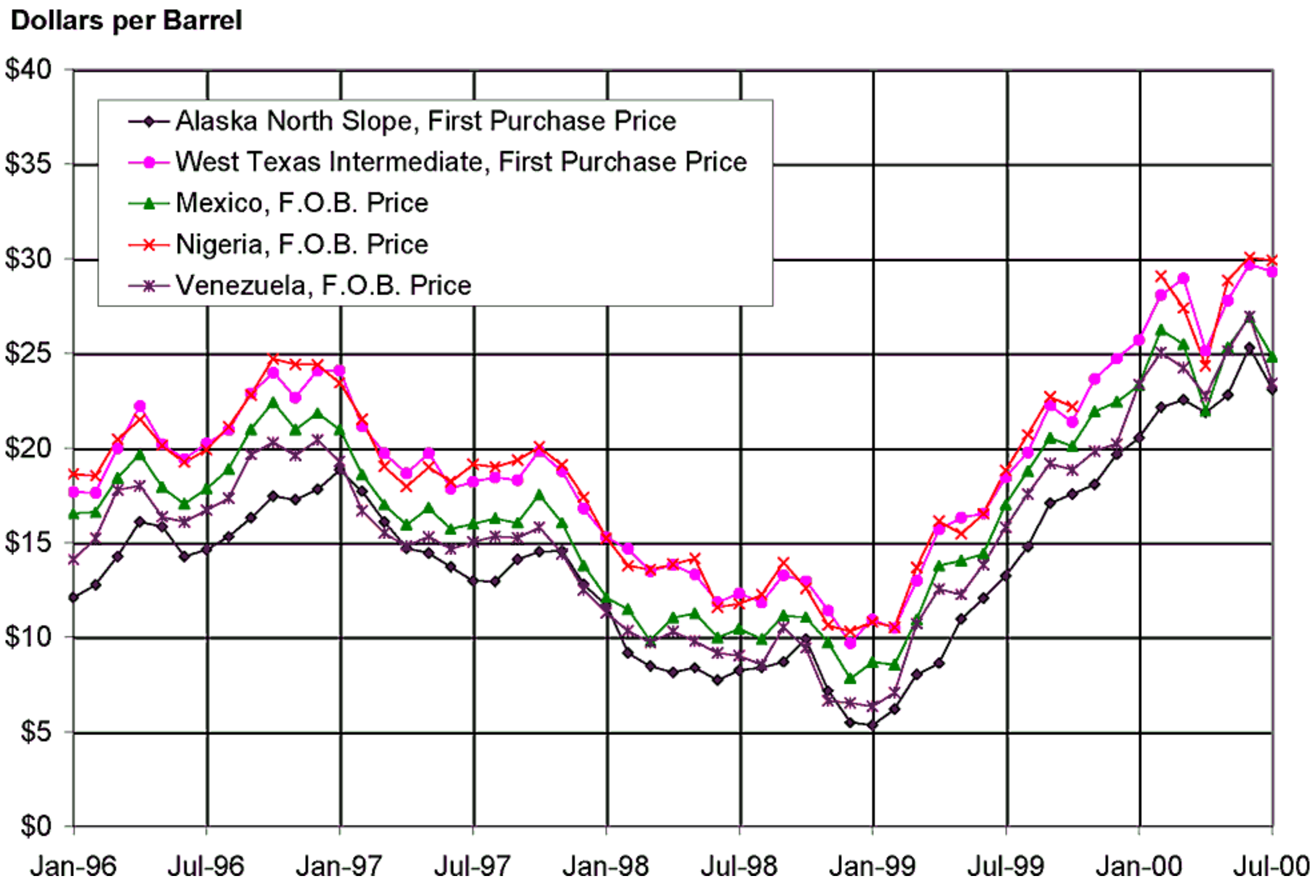

Figure 11 Crude Oil Prices Paid by US Refiners, 1996-2000

Source: Energy Information Administration, Petroleum Marketing Monthly

Exporting Countries (OPEC) had been able to exert real influence on global oil markets, and the first time ever that non-OPEC producers such as Mexico and Norway had gone along. At the same time, world crude oil demand had begun to recover as Asian economies emerged from two years of recession.

The result of these and other events, as demonstrated in Figure 10, was a dramatic increase in the price of crude oil over the next several months. The average price paid for a barrel of the benchmark West Texas Intermediate crude doubled from $10.49 in February 1999, to $22.23 in September, while the price of a barrel of Alaska North Slope crude tripled from $5.34 in January to $17.10 in September. Despite the higher prices, OPEC ministers decided at a September 1999 meeting to maintain existing levels of production at least until March 2000.

January and February of 2000 saw shortages of heating oil in the Northeast due to severe winter storms. Combined with general tightness in product markets, this drove spot prices for No. 2 distillate to the unprecedented level of $1.77 per gallon on February 4, 2000. However, heating oil customers outside the Northeast were largely unaffected, as the shortages were very localized. The high prices prompted President Clinton to announce the release of $125 million in additional federal government assistance for low-income households hit by high heating oil prices.

Crude prices dropped by some $5 per barrel in April after OPEC agreed to increase production by 1.5 million barrels per day, but jumped back up after low gasoline inventories and the premature introduction of new fuel standards led to skyrocketing gasoline prices in the Midwest in May and June. Crude oil and gasoline prices have trended higher since June, with West Texas intermediate crude generally trading between $30 and $35 per barrel. Prices dipped briefly in October after President Clinton announced that the government would release 30 million barrels from the Strategic Petroleum Reserve, but regained previous levels within a few weeks.

Besides indicating the extent of crude oil price volatility in recent years, Figure 11 demonstrates another interesting fact about crude oil markets. While national policy-makers like to focus on the distinction between domestic and imported crude, this figure shows that the prices actually paid by U.S. refiners for domestic crudes like Alaska North Slope and West Texas Intermediate rise and fall in lockstep with the prices paid for imported crudes.[3] This ought to be intuitive; more than perhaps any other commodity, crude oil trades in a global market where the primary factors affecting price are quality and the cost and availability of transportation. This means that initiatives to encourage domestic production of crude oil will have little, if any, consumer benefit, since they are unlikely to result in enough new supply to affect prices in the 80 million-barrel per day world market.

Supply effects of Olympic Pipeline explosion

On June 10, 1999, the Olympic Pipeline ruptured near Bellingham, Washington resulting in a series of explosions which killed three people and shut down the pipeline. The 16-inch diameter pipeline carries petroleum products south from the BP Amoco (previously ARCO) refinery at Cherry Point and the Tosco refinery in Ferndale. The pipe joins a 20-inch line that carries petroleum products from the Equilon and Tesoro refineries near Anacortes. South of Anacortes, the pipe is capable of carrying 330,000 barrels per day of refined petroleum products, or some 60% of the output of the four refineries. The pipeline then runs 400 miles to Portland, Oregon with terminals in Bayview, Renton, Seattle, SeaTac, Tacoma, Spanaway, Olympia, Vancouver, Linnton, and Portland. See Figure 12 for a map of petroleum pipelines and refineries in Washington. The section of pipeline between Ferndale and the terminal south of Anacortes has remained closed since the incident, cutting off the BP Amoco and Tosco refineries from downstream markets. The Equilon and Tesoro refineries still have access to the pipeline and are relatively unaffected by the incident.

While sporadic shortages of premium grades of gasoline were reported in the weeks following the incident, the region did not suffer any major supply disruptions. The industry’s response has included increased ship, barge, and truck transportation of refined products and exchange agreements between refineries so that pipeline product supplied by refineries in Anacortes can be traded with another company's product delivered to other locations by barge or truck. Gasoline is being barged to Harbor Island to supply the Seattle area, to Tacoma, and to Portland, which until the incident relied on the Olympic Pipeline for the majority of the fuel supplied to the area. BP Amoco, the largest refinery in the Northwest, has been running at about 70% of capacity since the incident; tanker shipments of refined products from California refineries to Portland appear to be making up the difference.

The most worrisome supply issue associated with the incident was the continued ability of SeaTac airport to receive jet fuel. SeaTac is supplied solely by the pipeline and is not set up to receive fuel from any other source such as tank trucks. SeaTac uses about 36,000 barrels per day of jet fuel, most of which is supplied by BP Amoco. BP Amoco has been able to continue to supply SeaTac by barging jet fuel to a terminal at Anacortes, where it is pumped into the Olympic Pipeline. However, SeaTac has had to reduce the amount of fuel normally stored on site.

The effect of the supply disruption on fuel prices appears to have been minimal. Washington prices were already high after a larger than normal springtime increase. Prices reportedly spiked in some areas immediately after the explosion, and the average price paid for gasoline in Washington increased from $1.41 per gallon in June of 1999 to $1.48 per gallon in July. However, crude oil prices were rising rapidly at that time, and the national average gasoline price rose 5¢ during the same period. Washington prices peaked at $1.52 in August

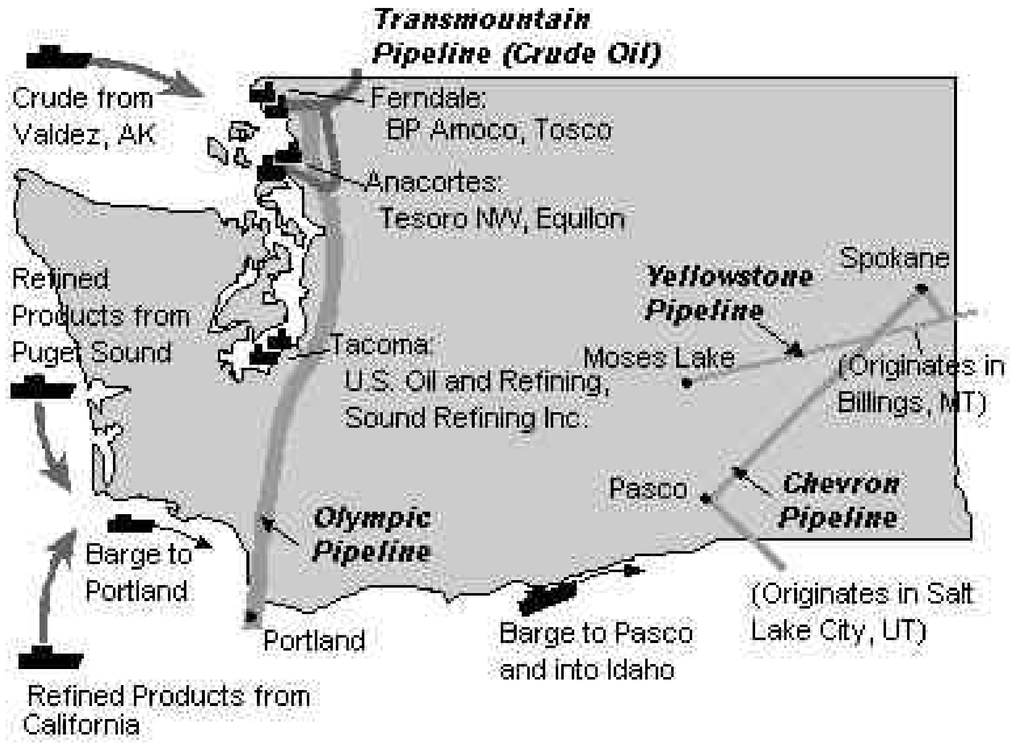

Figure 12 Petroleum Pipelines and Refineries in Washington

Source: Petroleum Industry Maps

before drifting downward to $1.44 by November, while national prices continued to increase through December.[4]

It is unclear when the pipeline will be able to resume normal operations. The pipeline failed a pressure test conducted in September 1999, and additional defects similar to those that caused the Bellingham rupture have been found near Kelso. BP Amoco took over operation of the pipeline from Equilon in June 2000, and appointed a new board of directors. The pipeline is co-owned by BP Amoco (37.5%), Equilon (37.5%) and GATX (25%). Meanwhile, the federal criminal investigation is continuing with no indication of when it may wrap up. The company is currently targeting the middle of 2001 for start-up, pending regulatory approval. The pipeline would operate at 70% capacity for two weeks, and 80% for one year. If no problems are encountered, the pipeline would go back to 100% sometime in 2002.

Oil Company Mergers

The last few years have seen a multitude of mergers among giant oil companies, many of them affecting companies that operate in Washington. The primary trend has been one of companies with different regional strengths merging to expand their reach to new parts of the country. However, some of the proposed mergers have raised antitrust concerns, both at the Federal Trade Commission (FTC) and with Washington's Attorney General. If completed, the recent mergers will mean that each of Washington's four largest refineries will have changed hands since 1993.

The most problematic from Washington's point of view was the merger between BP Amoco and Atlantic Richfield Company, or ARCO. BP and Amoco completed their $53 billion merger in January of 1999. Two months later, the new company announced its intention to acquire ARCO for $26.6 billion in stock. The move raised red flags in Washington because the combined company would control 75% of the Alaska North Slope crude oil supply. Washington, Oregon, California and the FTC settled with the companies in April 2000, after the companies made major concessions, including the sale of all of ARCO's interest on the Alaska North Slope to Phillips Petroleum. BP had already sold its Ferndale refinery and retail outlets in Washington to Tosco in 1996. Tosco is in the process of re-branding its BP stations with the "Union 76" brand. Existing ARCO and Amoco stations in Washington will eventually carry the BP brand.

Washington, Oregon, and California also intervened in the $80 billion merger of Exxon and Mobil, which was approved by the FTC in November 1999. The companies agreed to sell over 2,400 retail outlets, mostly in the Northeast, Texas, and California, and a refinery in California. A little further from home, the French and Belgian company TotalFina, created by a 1999 merger of the French company Total and the Belgian Petrofina, purchased France's Elf Aquitaine for $43 billion, and became TotalFinaElf.

The most recent proposed merger activity is Chevron's October 2000, announcement that it would purchase Texaco for $34 billion. This merger will likely face similar scrutiny as the BP Amoco-ARCO and Exxon-Mobil deals, as the combined company would control about 36% of the retail market in Washington, Oregon, California, Arizona, and Nevada, along with about one-third of the refinery capacity on the West Coast. Texaco was already involved in a 1998 merger in which it combined its downstream operations in the U.S. with Shell to form Equilon. Equilon operates the former Texaco refinery in Anacortes and retail stations branded as either Texaco or Shell. To gain approval of that deal, Shell sold its Anacortes refinery to Tesoro. Table 5 lists the changes in refinery ownership since 1993.

Current Owner	Previous Owner	Ownership Details	Location	Capacity (bbl/day)[5]
BP	ARCO	BP Amoco merged with ARCO in 2000	Cherry Point	222,720
Equilon, may soon be owned by Chevron	Texaco	Texaco and Shell merged downstream operations in 1998 to create Equilon. Texaco agreed in 2000 to be purchased by Chevron.	Anacortes	142,000
Tesoro	Shell	Sold by Shell to Tesoro in 1998 when Texaco and Shell merged their downstream operations to form Equilon.	Anacortes	107,500
Tosco	BP	The plant was originally owned by Mobil Oil Corp, was sold to BP Oil Corp in 1988, and then sold in 1993 to Tosco Northwest Co.	Ferndale	88,500
U.S. Oil and Refining			Tacoma	30,800

Table 5 Washington Refinery Ownership

Source: Energy Information Administration, Petroleum Supply Annual

[1] Sources for the chronology of market events discussed in this chapter include wire services, newspapers, and the Energy Information Administration's *World Oil Market and Oil Price Chronologies*, http://www.eia.doe.gov/emeu/cabs/monchron.html.

[2] Oak Ridge National Laboratory, Transportation Energy Data Book 20, November, 2000. ORNL-6959 (Edition 20 of ORNL 5198), http://www-cta.ornl.gov/data/tedb20.

[3] The actual prices for different crude streams can vary for a number of reasons, chief among them the quality of the crude (e.g., sulfur content, specific gravity, etc.) and the cost of transportation to refineries that are configured to process that type of crude. The price of Alaska North Slope crude, for example, is typically lower than other crudes because it is a medium-weight, high-sulfur crude in a very remote location. However, the price *trends* are nearly identical for all crudes over periods of several months or more, a demonstration of the fungibility of crude oil in world markets.

[4] Energy Information Administration, Petroleum Marketing Monthly, http://www.eia.doe.gov/oil_gas/petroleum/data_publications/petroleum_marketing_monthly/pmm.html.

[5] Energy Information Administration, Petroleum Supply Annual, http://www.eia.doe.gov/oil_gas/petroleum/data_publications/petroleum_supply_annual/psa_volume1/psa_volume1.html.

CHAPTER 3 NATURAL GAS

Natural gas is an increasingly important part of the state's energy mix. Prior to the construction of the Northwest Pipeline in 1957, natural gas was unavailable in the Northwest, although the major urban centers were served with manufactured gas made from coal or oil. Initially, the pipeline and local distribution utilities served primarily industrial process heat loads in the forest products industry. In the 1980's, as home heating oil felt the impact of the oil embargoes, and electric prices increased with the addition of coal and nuclear generating resources, natural gas became the fuel of choice in the residential sector. Today approximately half of the homes in the state use natural gas for heating. In the 1990's, a rapid increase in the use of natural gas to generate electricity led to a sharp increase in state natural gas demand.

Washington is served by two interstate natural gas pipelines and seven natural gas distribution utilities. See Figure 13, Washington Natural Gas Pipeline Infrastructure.

Williams Pipeline Company operates the Northwest Pipeline which brings supplies from the Canadian border near Sumas into Washington and exits the state at two locations: south at Vancouver and east at Plymouth. Pacific Gas Transmission brings gas from Alberta into eastern Washington and exits the state near Pasco en route to California. The two pipelines interconnect just below the Washington border near Hermiston, Oregon and gas from either can be delivered to any point in the state where gas service is available. In addition, three connections exist at the Canadian border near Sumas, providing gas from the Canadian system to the Cherry Point industrial area near Bellingham, to the Sumas Energy electric generating plant, and to Cascade Natural Gas.

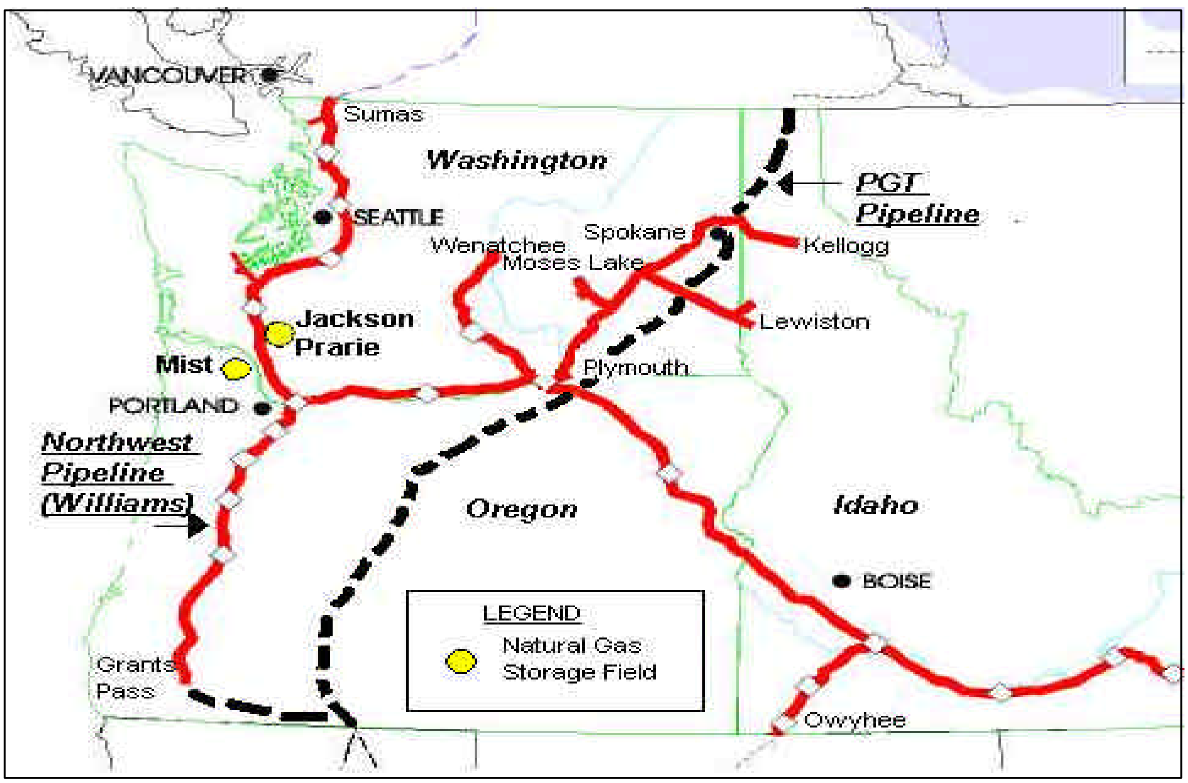

Figure 13 Washington Natural Gas Pipeline Infrastructure

Source: Natural Gas Industry Maps

The four investor-owned natural gas utilities serve nearly all of the natural gas consumers in the state. Avista Utilities (formerly Washington Water Power) serves the Spokane and Pullman area. Northwest Natural Gas serves the Vancouver region. Puget Sound Energy (formerly Washington Natural Gas) serves King, Pierce, Snohomish, Thurston, and Kittitas counties. Cascade Natural Gas serves pockets of customers in many areas of the state, including Wenatchee, Yakima, Walla Walla, Tri-Cities, Bellingham, Mt. Vernon, Anacortes, Bremerton, Aberdeen, and Shelton. In addition, small natural gas distribution systems are operated by the City of Ellensburg and the towns of Enumclaw, and Buckley.[1]

PRICE INCREASES

Historically, gas prices have tracked oil prices, and gas demand has responded to changes in prices. In the 1970's, rising prices led to falling demand as industries learned to squeeze more productivity out of their gas consumption. In the 1980's, declining gas prices coupled with rising electric prices led to a surge in the use of natural gas for home heating, and gas sales went up sharply. Figure 14 shows regional natural gas consumption, measured on the left axis, and real (inflation adjusted) gas prices measured on the right axis: During the summer and fall of 2000, wholesale natural gas prices in the Pacific Northwest more than tripled, compared with the previous year. This led to retail rate increases of approximately 50% to residential and commercial customers of Washington's natural gas utilities. In early December 2000, daily spot market prices for natural gas spiked to as much as $30 per million Btu[2], some twenty times the price two years earlier, and ten times the price reached just six months earlier. Annual contract prices also soared, from less than $2 per million Btu to as much as $6 per million Btu.[3] The short and long-term impact that this surge in prices will have on gas usage has not yet been measured. This sudden increase in price is explained by a combination of factors. First and foremost, the natural gas industry has gone from a position of surplus, with "glutted" markets, to a position of relative balance between supply and demand. The Northwest no longer enjoys a "buyers market" for natural gas because of growth in gas demand within the region, growth in demand outside the region, and construction of a new pipeline to the Midwest.

Second, oil prices surged during 2000 as the global economy recovered without a commensurate increase in oil production. The linkage between natural gas and oil prices is due to the fact that for many applications, particularly industrial fuel supply and petrochemical and plastics manufacturing, oil and gas are substitute fuels. When the gas industry was in surplus, from 1995 - 99, this linkage became relatively weak, but as the industry came into balance, fuel substitution became relevant.

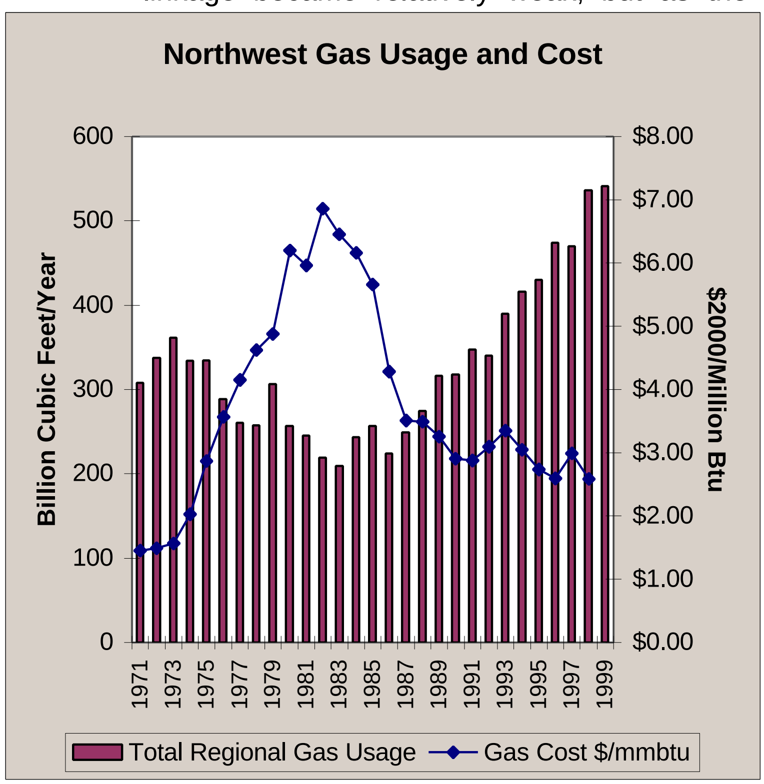

Figure 14 Northwest Natural Gas Usage and Cost

Source: Energy Information Administration, Bureau of Labor Statistics

Finally, electric load growth on the West

Coast, combined with relatively dry hydroelectric conditions has led to much greater reliance on natural gas for electric generation in 2000 than in recent years. The large magnitude and sudden change in gas demand has resulted in sharp short-term increases in gas price.

The wholesale natural gas market is unregulated, and prices move on a daily basis as buyers and sellers negotiate transactions. There are no constraints on price by either the U.S. or Canadian government. The Washington Utilities and Transportation Commission has historically allowed local gas distribution utilities to pass through any wholesale price changes on an actual cost basis. This policy led to a price increase of 50% and more during the summer and fall of 2000. Figure 15 shows wholesale natural gas prices at the Washington/British Columbia border over the past year and a half; the spike in prices in December 2000, caused by increased demand for natural gas for electric generation coupled with cold weather in California and the Northwest, is extraordinary and unprecedented.

Table 6 shows the average residential natural gas rates in effect for Washington's four investor-owned gas utilities on January 1, 1999, January 1, 2000, and November 1, 2000.

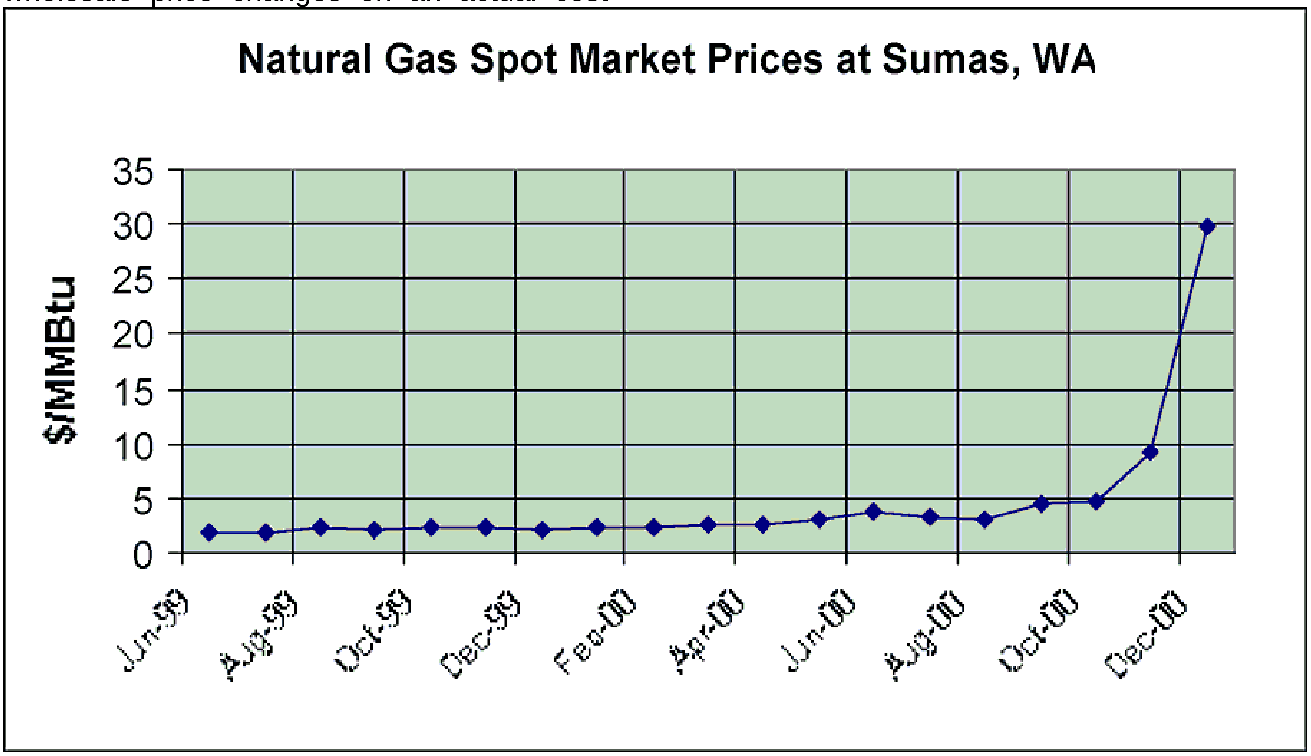

Figure 15 Natural Gas Spot Market Prices at Sumas, WA

Source: Natural Gas Weekly

IOU Gas Utility	January 1, 1999	January 1, 2000	November 1, 2000
Puget Sound Energy	.489	.570	.737
Avista Utilities	.379	.430	.594
Cascade Natural Gas	.568	.625	.700
Northwest Natural Gas	.510	.575	.715

Table 6 Residential Gas Prices, dollars per therm

Source: Washington Utilities and Transportation Commission

Demand for Gas has Increased

The demand for natural gas has increased sharply in recent years. This is one reason why prices have increased. The first reason for the increase in demand is a large number of new natural gas fueled electric generating facilities have been constructed and connected to the natural gas pipelines which serve the state. Second, gas is almost the universal choice of new home buyers for space and water heating where gas distribution service is available, and residential gas consumption has grown at more than twice the rate of the state's population. Finally, until the summer of 2000, gas prices had declined sharply in inflation-adjusted terms. Figure 14 shows both the demands for gas in the Northwest and bulk gas prices.

The biggest change in natural gas usage has been for electric generation. The use of natural gas for electrical generation is a relatively new phenomenon in the Pacific Northwest. Prior to 1990, a number of gas-fired power plants were constructed, but these were typically used only for meeting peak demand during a few of the coldest days of the year. Beginning in 1991, several power plants were built at industrial facilities, producing both process heat for the industries and electricity in a process known as "cogeneration." Since 1996, stand-alone gas-fired electric generating plants have been installed in several locations in and near the state, and many more are proposed for construction.

Name	Location	Date	Size (MW)	Type
March Point 1 & 2	Anacortes	1991	140	Cogeneration
Encogen 1, 2 & 3	Bellingham	1993	160	Cogeneration
Sumas I	Sumas	1993	125	Cogeneration
Tenaska I	Ferndale	1994	245	Cogeneration
Rathdrum 1 & 2	Idaho, near Spokane	1995	176	Cogeneration
Hermiston 1 & 2	Oregon, near Pasco	1996	469	Cogeneration
River Road	Vancouver	1997	248	Combined Cycle
Coyote Springs	Oregon, near Pasco	1997	237	Cogeneration

Table 7 Northwest Natural Gas Power Plant Additions, 1991 - Present

Source: Northwest Power Planning Council

Residential and commercial use of natural gas is expected to continue to increase. The demand forecasts of the state's natural gas utilities project annual increases in gas usage of 2% - 4%[4]. This growth is expected to be served primarily by increasing utilization of existing pipelines, and activation of additional natural gas storage fields at Jackson Prairie (south of Chehalis) and at the Mist, Oregon storage field owned by Northwest Natural Gas Company.

Future growth in natural gas demand will be heavily affected by decisions to build additional natural gas fired power plants, and the magnitude and timing of this is highly uncertain. The Washington Energy Facility Site Evaluation Council (EFSEC) has approved four new gas fired power plants, and is considering applications for up to four more. In addition, several plants which are smaller than the 250 megawatt EFSEC threshold are currently proposed for construction. Table 8 lists approved or active power plant proposals which would use the pipeline system serving this state:

Name	Location	Size (mw)	Status
Under Construction			
Rathdrum II	Rathdrum, ID	270	Under Construction, Operation in 2001
Hermiston II	Hermiston, OR	536	Under Construction, Operation in Summer 2000
Klamath Falls	Klamath Falls, OR	484	Under Construction, Operation in Summer 2002
Approved for Construction			
CGF	Chehalis, WA	520	Approved by EFSEC (*)
Weyerhaeuser	Longview, WA	405	Approved by EFSEC
Energy Northwest	Satsop, WA	532	Approved by EFSEC
NRPF	Creston, WA	838	Approved by EFSEC
Delta	Everett, WA	249	Approved by local authorities
In Licensing Process			
Sumas II	Sumas, WA	660	EFSEC decision due
Starbuck	Starbuck, WA	1100	EFSEC potential Site Study underway
Newport	Wallula, WA	1300	EFSEC potential Site Study underway
Mercer Ranch	Kennewick, WA	850	EFSEC potential Site Study underway

Table 8 New Natural Gas Power Plants

(*) Amendment Pending

Source: Northwest Power Planning Council

To put this into some perspective, if the five plants already approved for construction were built, natural gas consumption in the state would increase by approximately 70%. If only two of the four plants in the EFSEC licensing process" were built as well, natural gas consumption would double. There is no certainty that the natural gas pipeline infrastructure could accommodate all of these plants being built, and it would be speculative to predict the impact on the reliability of supply of natural gas or the price of natural gas were these plants to be built.

If a significant number of new power plants are constructed, there will be substantial pressure on both the supply of natural gas and the capacity of natural gas pipelines connecting the Northwest to the sources of gas supply. A separate report on this subject is anticipated to be published by the OTED Energy Division in early 2001.

Pipeline Capacity

Washington has no natural gas production within its borders. Our natural gas comes from the Rocky Mountain region of the U.S. and from Alberta and British Columbia. Each of the three points of entry has operated at or near capacity in recent years, but the capacity of the pipelines is being periodically upgraded to meet new demand. Pipeline upgrades take two forms. Additional compression capacity can move increased amounts of gas within the existing pipe or when that capacity is exhausted parallel pipelines must be constructed. The former can usually be done economically and quickly, while the latter is time consuming and expensive.

Because these three pipelines serve more than just the state of Washington, it is important to refer to their capacity in regional terms. Pacific Gas and Electric Company, Gas Transmission Northwest (PGT) serves Idaho, Washington, Oregon, and California, and the majority of its capacity is committed to California. Northwest Pipeline serves

Washington, Oregon, and Idaho. It connects at Sumas to West Coast Pipeline, a Canadian line that also provides service to all of British Columbia.

PGT has a huge capacity at the Canadian border, some 2.8 billion cubic feet per day, but over two-thirds of this is committed to California customers. The amount available to serve the state of Washington is similar to that of Northwest Pipeline's southern system. If the Creston, Starbuck, or Wallula power stations were built, the capacity of PGT would need to be augmented.

Northwest Pipeline's southern system brings Rocky Mountain gas to the state, entering the state near Pasco. This is the smallest of the three pipelines serving the state, able to carry approximately 400 million cubic feet per day, or about 20% of the region's daily usage. This line has not been upgraded in recent years, largely because the domestic gas has not been price-competitive with western Canadian gas. The recent opening of the Alliance Pipeline from Alberta to Chicago has provided a new outlet for Canadian gas, and the price differential between the Northwest and the Midwest has evaporated. In fact, under current conditions, with high levels of natural gas use in California and the Northwest for electric generation, pipeline capacity constraints have led to short-term sharp increases in natural gas prices in the West Coast market.

Northwest Pipeline's northern system, connecting to West Coast Pipeline at Sumas, is the largest source of gas for the state. This linkage is operating very close to capacity at the current time. Two upgrades to the capacity of West Coast have been designed; together they would increase capacity by about 300 million cubic feet per day. One-third of that upgrade is needed to serve core-market growth (residential and commercial) while two-thirds is available to meet increased demand for gas from electric generating plants. That amount of capacity is approximately half of what would be required if all of the gas-fired generating plants currently approved for construction in Western Washington were built. West Coast has no immediate plans for additional capacity, because it does not believe that very many new generating plants will be built.

Summary

The natural gas industry in the Pacific Northwest has undergone a dramatic transformation in the 43 years since the Northwest Pipeline was constructed. Initially serving primarily industrial loads, the gas industry now serves half of the homes in the state. Rapid growth in gas demand for electric generation has led to supply/demand imbalance, and (at least temporarily) soaring wholesale costs for natural gas. If the gas industry is able to respond to this increased demand with new supplies and additional pipeline capacity, gas prices may moderate in the future. If supply and pipeline capacity is outstripped by new gas demand, however, high prices could be with us for a long time to come. The dramatic price surge in the winter of 2000 - 2001 may be just the beginning of a new era in gas scarcity and price, or it may be a temporary condition caused by a rare combination of weather and economic conditions.

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[1] Additional information, including service area maps, is available at the Northwest Gas Association website: http://www.nwga/org

[2] Wholesale gas is traded in units of 1 MMBtu, or million British thermal units. Retail rates for gas utilities are per "therm." A therm is 100,000 BTUs, or one-tenth of the size of the wholesale units. A Btu is the amount of heat needed to raise one pound of water one degree Fahrenheit. A typical home heated with natural gas uses 800 therms (80 million Btu) per year.

[3] Source: Reuters Commodities: www.commods. reuters.com

[4] Source: Least Cost Plans filed with the Washington Utilities and Transportation Commission by Puget Sound Energy, Avista, Cascade, and Northwest Natural Gas Companies.

CHAPTER 4 ENERGY EMERGENCY PLANNING AND RESPONSE

Energy supply shortages or disruptions can ultimately affect every person and every economic sector in the state. The ability to anticipate supply shortages and respond appropriately to supply disruptions — such as the effect of thermal plant outages, wildfires, and market forces on the electric system this summer or the effect on the petroleum supply resulting from the Olympic Pipeline explosion in 1999 — can help mitigate the severity of emergencies. Natural disasters such as earthquake, fire, flood, severe winter or summer weather conditions, or geopolitical events such as war, terrorism, civil disturbance, or embargo can cause a shortage. In some unique circumstances, government response to high-energy prices is also warranted.

The Energy Division of the Office of Trade and Economic Development (OTED) lends expertise to utilities and other state agencies as needed to mitigate the effects of acute system failures and localized outages. By statute, the Energy Division is also responsible for administering contingency plans; coordinating a response to petroleum and electricity supply shortages; and administering the Governor's energy emergency powers.[1]

Safe and reliable supplies of energy underpin essential services such as heating, lighting, refrigeration, transportation, and communications. Energy emergencies — supply shortages or disruptions — can be extraordinarily devastating. They have economic consequences and they can threaten lives and property.

Electricity emergencies have the greatest potential for causing loss of life and affecting health and safety. Unlike oil and gas emergencies, where electricity can be substituted to provide heat, the loss of electricity shuts off all heating systems that require ignition or fans. Electricity emergencies also affect lighting, water and sewer processing and pumping services, food processing, refrigeration, communications, Internet service, life support systems, security systems, banking and bankcard services, and gasoline pumping.

Prevention provides the first line of defense. Energy distribution companies design strong and redundant systems to guard against failures. But failures will occur, and contingency plans are needed to address a full range of emergency situations — from localized outages to region-wide disasters. Energy suppliers handle most emergencies, with the state providing assistance as needed. In more severe emergencies, the state plays a larger role.

Types of Emergencies

Washington's energy systems are vulnerable to two types of emergencies: *acute system failures*, usually caused by accidents or severe weather, and *supply shortages*.

Acute System Failures

All energy delivery systems are vulnerable to accidents and disasters. However, petroleum and natural gas disruptions are quite rare and tend to have economic rather than life-threatening consequences. Electricity system failures are more common and more serious. There has been growing concern that power outages may become more common as electricity restructuring increases the number of energy suppliers using the grid to transmit power, and as utilities attempt to cut costs in the new competitive environment by limiting investments in maintenance and upgrades.

With increasing reliance on natural gas-fired electricity generation, there may be more potential for combined natural gas/electricity emergencies. During very cold weather there could be strong demand for natural gas for both heating and electricity generation. For example, during a cold snap in November 2000, three large southern California power generators had to switch to fuel oil as San

Diego Gas & Electric curtailed natural gas deliveries in order to be able to provide sufficient gas to residential and commercial customers. San Diego Gas and Electric delivered more gas on November 13, 2000 than on any other day on record, beating peaks set in January 1999. Clearly, as demand increases, the infrastructure will have to expand[2].

Acute electric system failures usually result from storms or accidents that damage facilities and equipment. When this happens, the supply of energy cannot reach users until the damage has been repaired and service restored.

During the summer of 2000, the Western Interconnection faced a number of challenges to system operations based on structural fires and wildfires. On July 28, a fire broke out in one of the powerhouses of Grand Coulee Dam, bringing down one third of the largest hydroelectric facility in the region. Nine out of 16 generators were back on line by July 30 and following investigations and repair, full capacity was restored by early August. Another fire that broke out in the Columbia Generating Station, the only operating nuclear facility in the region, caused safety and power supply concerns. Heavy smoke from Montana wildfires caused arcing on the large transmission lines delivering electricity to the Northwest from power plants in Colstrip. Although the plants were operational, transmission of the power was not possible until the smoke subsided and the transformers could be repaired.

The petroleum industry has also dealt with system failures resulting from accidents. In 1999, the Olympic Pipeline explosion in Bellingham and the resulting closure of the pipeline between Bellingham and Anacortes required extensive efforts on the part of the refineries in order to get petroleum products to end users. Response included exchange agreements with refineries in Anacortes for space on the southern portion of the pipeline that is still in operation, and increased transportation of petroleum products by truck and barge. SeaTac airport presented a particular challenge since it can ONLY be supplied by pipeline. SeaTac has no marine access for petroleum barges and the huge volume of fuel required cannot be met by trucking product. Cherry Point and Ferndale refineries ended up barging fuel to Anacortes where it was then transferred to the pipeline for delivery to the airport. These measures will continue until the pipeline reopens, tentatively set for the summer of 2001.

Supply Shortages

Longer-term energy supply shortages can result from accidents or disasters. Localized shortages can also develop, however, if customers or distributors engage in panic buying because they anticipate higher prices or future supply shortages. This exceptional demand can outstrip the distribution system's ability to respond.

More extensive energy shortages normally result from a broader set of causes. For example, war in the Persian Gulf could create a severe worldwide shortage of oil. Drought in the Northwest could set the stage for insufficient winter supplies of electricity. Because shortages have different causes and effects than acute system failures, they require a different response. Demand needs to be restrained to meet available supply until supply can be increased. Repairing facilities usually does not factor into the response.

Unlike most acute system failures, addressing significant energy shortages requires substantial state involvement. Efforts center on getting the public to respond by reducing energy consumption. State leadership in raising public awareness and educating consumers is critical.

Allocating scarce energy supplies to ensure that essential service providers have fuel may also be required. Because allocation can be quite contentious, state leadership is required to ensure effective and equitable distribution. In the case of extreme shortages, some rather demanding steps may have to be taken — such as waiving environmental restrictions on certain types of energy production. This can only be done under the guidance and authority of the Governor's emergency powers.

Response for Petroleum Shortages

The major impact of most petroleum shortages is economic: prices rise to reflect limited supplies. Steep or rapid rises in price can cause a variety of economic problems. These problems adversely affect people with low or fixed incomes. Businesses that depend heavily on transportation may be threatened by increased cost of doing business. Furthermore, if a shortage is very extreme, pricing alone cannot guarantee sufficient fuel to essential service providers.

In such an event, Energy Division staff would prepare the state for the possibility of a major oil shortage. Efforts would concentrate on public education and the preparedness of state agencies, local governments, essential service providers, and transit agencies. Arrangements would be made with oil companies for responding to critical needs and administering fuel allocations in case such steps were necessary. During an emergency, the Energy Division would inform the public through the news media of the status of the emergency, the stage of emergency, and whether specific actions are recommended or mandated.

The Implementation Guide for the Petroleum Products Contingency Plan[3] calls for the Energy Division to undertake a phased array of increasingly stronger response actions corresponding to the severity of a crisis. The plan operates under the assumption that a combination of market forces (such as price changes) and government intervention (such as the dissemination of information about an emergency) work together to reduce petroleum consumption and allocate scarce supplies. The plan relies more heavily on market forces early in a crisis. The Energy Division plays a central role coordinating state-level decision making and emergency information communication. However, most actions that will help the state weather a petroleum emergency must be taken by individual agencies, businesses, and citizens.

As of the publishing of this report, the state's existing Petroleum Products Contingency Plan is being updated. Energy Division staff will also review and revise the administrative rule for dealing with petroleum emergencies to reflect changes in the industry, in federal regulations, and in policies for addressing petroleum shortages.

Response for Regional Electricity Shortages

One type of electricity shortage is the inability to meet daily peak demand. The Northwest's vast hydroelectric system historically has provided a peaking capacity far beyond Washington's daily needs. However, some areas of the state, notably the Puget Sound region, are beginning to experience occasional difficulty meeting daily peak demand. This emerging problem results from a combination of transmission constraints and bottlenecks and lack of sufficient local generation, and is being addressed by the utility industry.

Electricity systems also have seasonal peaks. California and the Southwest experience peaking in the summer because of their large air conditioning load. The Northwest exports surplus power to California and the Southwest during the summer months. Washington's peak comes in the winter when demand for heating increases. Utilities can foresee a shortage by monitoring reservoir levels and weather. As fall and winter progress, utilities can work to avert such a shortage by increasing the operation of thermal and nuclear generation and purchasing more energy from out of state, including California and the Southwest. The result can be higher energy costs, but no winter shortage. Years of both drought and extreme cold weather are those where such a shortage is most likely.

During the next several years, however, there is an increasing possibility of power supply problems, even taking into account both regional resources and the availability of imports. According to a Northwest Power Planning Council (NWPPC) report, Western Interconnection peak loads have increased by nearly 12,000 megawatts while generating capacity only increased by 4,600 megawatts between 1995 and 1999.[4] The peak load increase would have been even greater if 1999-2000 had not been a relatively mild weather year. This year, weather forecasters are predicting more normal cooler seasonal temperatures, meaning that electricity demand is likely to be higher.

Pacific Northwest Winter 2000-01 Energy Emergency Plan

Because of the risk of possible electricity shortages, electricity emergency response procedures need to be in place. This effort includes an inventory of the actions that could be taken to cut back on electricity demand if needed, the trigger points for taking these actions, clear definitions of roles and responsibilities, and a communications plan to inform the public. A task force comprised of the Pacific Northwest Utilities Conference Committee, the Northwest Power Pool (NWPP), the Bonneville Power Administration, the NWPPC, and the Northwest states and utilities has developed a joint Proposed Pacific Northwest Winter 2000-01 Energy Emergency Plan. The draft plan is designed to help ensure that energy shortages don't translate into blackouts. The plan:

1. Institutes a warning system that will give energy operations personnel notice of impending problems and thus provide lead time to take steps to avert an emergency. Warnings will identify the intensity of a potential emergency--level one through three--with three being the most serious.
2. Ensures actions are consistent with Federal Energy Regulatory Commission standards of conduct and North American Electric Reliability Council criteria.
3. Sets up an Emergency Response Team (ERT) to facilitate a coordinated regional approach to a potential emergency. This team would evaluate the status of the system and determine if a warning should be issued or terminated.
4. Sets up a communications system to give accurate and timely information to system operations personnel, policymakers, and the public.
5. Establishes objective criteria for determining what constitutes an approaching emergency based on an analysis of electricity loads and resources.
6. Reinforces that certain steps such as relaxing air quality standards or fish mitigation measures would be taken only after other actions have been exhausted.
7. Provides a safe and confidential repository that allows utilities to pool market-sensitive information without fear that individual information about needs or resources would be compromised. This will give a fuller and more accurate picture of the region's overall electricity loads and resources.

The plan will complement, not replace, state, federal, and individual utility emergency plans.[5]

Although the Winter Energy Emergency Plan was still in draft stage and there were plans to exercise the plan to ensure that participants were familiar with the procedures, a serious cold front initially forecast during the first week in December, 2000 initiated "on the job" training on the energy emergency plan for the ERT of Northwest utilities and government representatives. The arctic front was forecast to move in over the weekend of December 9 and 10 and hit hardest December 11 through 14. Temperatures were predicted to be 17 to 19 degrees below normal on the westside of the state, and 17 to 23 degrees below normal on the eastside.

The NWPP gathered and analyzed weather, transmission, generation, and load information and quickly decided to convene the ERT for a briefing on December 6. Members of the team agreed that even though energy supplies were are tight, at this point the region's transmission system and generation plants were in good shape. By consensus, the ERT stopped short of calling a "Regional Emergency Warning of a Potential Energy Alert" at that time. The team agreed to monitor the situation closely because any unplanned outages or further temperature drops could cause major problems. The ERT was scheduled to meet again by conference call on Friday morning, December 8, to reassess the situation.

Meanwhile, regional utilities and federal operating agencies began taking steps to prepare for the cold snap, such as deferring planned maintenance outages of transmission and power plants, working to maximize generation output and energy imports, reducing demand for electricity, and adopting a "no touch" policy - basically making no alterations to facilities that could trigger outages.

California, which normally supplies power to the Northwest in the winter is currently having serious problems of its own and is not expected to be able to offer assistance to the Northwest to any major extent. Energy supplies will continue to be very tight throughout the west this winter.

On December 7, the governors of California, Idaho, Oregon, Utah, Washington, and Wyoming held a conference call to discuss the electricity crisis that could occur in a few days if the temperature got as cold as predicted. The Western Governor's Group met again on December 11, to exchange information, and although the immediate crisis seemed to be abating, they agreed to reconvene in the future for similar calls as appropriate.

During the conference call on December 8, the ERT group received an update on weather conditions and the approaching arctic front that was expected to be region-wide. In addition, the Northwest Security Coordinator provided an overall assessment of the load resource balance in the region. Based on the information provided, the Northwest utilities, federal hydro operation agencies, and state governments participating in the call agreed that the Northwest Security Coordinator should issue a "Regional Emergency Warning of Potential Alert 2." A warning, however, does not constitute an emergency. Rather, it is designed to give the Northwest energy community time to take steps to avert an emergency. The ERT scheduled another conference call for Sunday, December 10.

Utilities and government representatives shifted into high gear to get word out to residents, businesses, industry, and governmental entities to do whatever possible to reduce their use of electricity. The energy community called on the public to take steps to conserve energy, such as turning off unnecessary lighting and electrical equipment, using energy-intensive appliances during non-peak hours, wrapping water heaters, weather stripping and caulking, and other measures that will make homes more energy efficient.

In addition, the governors of Oregon and Washington jointly called upon the residents and businesses in their states to begin conserving as much electricity and natural gas as possible in hopes of avoiding power disruptions when the cold weather arrived.[6]

Also occurring on December 8 was a conference call for all western state energy offices and electric and natural gas industry representatives to provide an overview of the situation for Federal Department of Energy officials.

On December 10, information presented convinced the ERT to maintain the Level 2 Warning, review the weather situation and electric system data and meet again by conference call on Monday, December 11. During the December 11 conference call, consensus again indicated that the Level 2 Warning should remain in place and be reassessed on Tuesday, December 12.[7]

At its December 12 meeting, the regional ERT terminated the Level 2 Warning.[8] The ERT did not drop down to a Level 1, but recalled the warning status altogether, based on a combination of factors:

- Public, state and utility actions to avert an emergency were working.
- Temperatures, while still below normal, were less extreme than predicted.[9]
- Forecasts indicated a shorter arctic front. By December 17, temperatures were expected to be just slightly below or near normal.

The region's utility community and states will continue to monitor the region's balance of power for resources and demand throughout the winter. The NWPP is compiling data on an ongoing basis. While conditions seemed to be returning to normal in mid-December, a new cold front or the loss of a regional generation or transmission resource could bring about new warnings. Power supplies throughout the West remain stretched. Winter has not yet officially begun. Precipitation has been far below normal. If conditions change, the ERT will reconvene immediately.

The newly created energy alert warning system was designed to give the region time to take pre-emptive actions on a voluntary basis to avoid an emergency, and it appears to have been successful in its first test. The plan will be evaluated and revised based on lessons learned during its first trial.

"The response was an unprecedented level of regional cooperation and coordination among the region's states and the energy community," Rich Nassief, Director of the NWPP, said. "There are still bumps to be ironed out, but it's obvious we needed an emergency preparedness plan and it worked."

State and Regional Curtailment Plans for Electric Energy

The Northwest's dependence on hydro-electricity also makes us particularly vulnerable to drought (see Figures 16 and 17). Drought conditions over an extended period of time could also cause a regional electricity shortage. The provinces and states of the NWPP (Washington, Oregon, Idaho, Wyoming, Nevada, Utah, Montana, British Columbia, and Alberta), coordinate operation of the hydroelectric system to maximize its efficiency and potential.

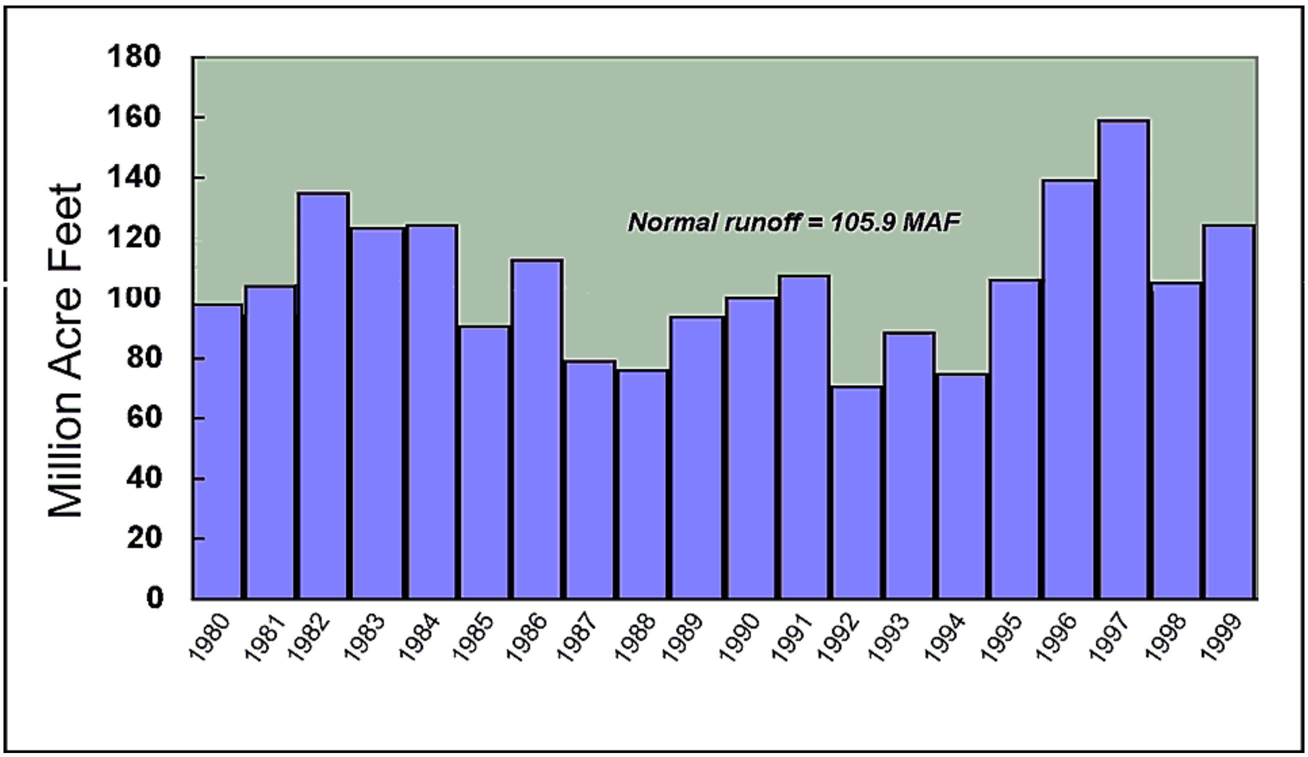

Figure 16 January - July Runoff Colombia River at the Dalles

Source: Energy News Data, Clearing Up, Issue No. 952, 10/23/00

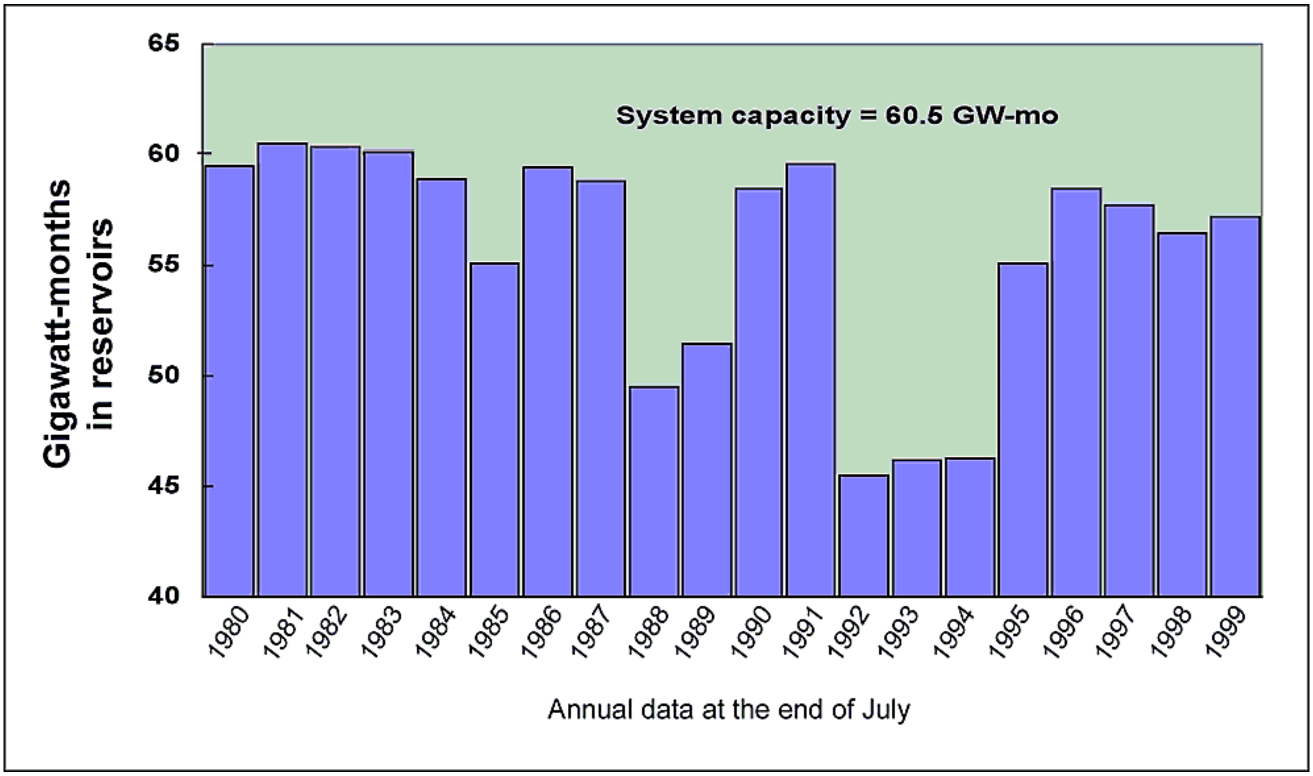

Figure 17 Below Normal Water Storage a Result of Recent Droughts

Source: Energy News Data, Clearing Up, Issue No. 952, 10/23/00

In addition, a single, large transmission grid interconnects the entire Western United States. Within the grid, electrons do not recognize state borders. If there ever is insufficient energy to meet load on the grid, all Western states could be affected by the shortage. Recognizing the regional nature of electricity supplies, the four Northwestern states have adopted a regional approach for managing a shortage.

The Northwest's electric utilities, public utility commissions, and state energy offices worked together to update the Regional Curtailment Plan for Electric Energy. The four states used the regional plan as a model and adopted similar state plans. In November 1994, the Washington State Curtailment Plan for Electric Energy was adopted as administrative rule (WAC 194-22).

The plan calls for the four Northwest states to initiate curtailment actions jointly. Washington's plan emphasizes voluntary curtailment and equal curtailment requirements for residential, commercial, and industrial customers. The plan has five stages; each level represents a more severe shortage that requires sterner steps. The first two stages are voluntary. The final three stages are mandatory. Consuming sectors are treated equally until stage four, where greater requirements to reduce consumption are placed on commercial and industrial customers. State law requires that such emergencies be implemented by the Energy Division under the guidance and direction of the Governor's Office.

The Washington State Curtailment Plan for Electric Energy establishes the process by which the state of Washington and Washington State utilities will initiate and implement statewide electric load curtailment when there is an insufficient supply of electric energy. The Energy Division would activate the plan during regional electricity situations where curtailment is necessary.

The Governor's Energy Emergency Powers

Under the most severe emergencies, an emergency legislative committee is convened and the Governor's emergency powers are activated (RCW 45.21G, see Appendix B). Energy emergencies are recognized as having the potential to cause extreme risk to life, health and welfare, and to require quick and unusual action. For this reason, the governor is required to take the lead in addressing an emergency and is provided extraordinary powers. The legislature advises the governor, state agencies implement the governor's response programs, and citizens and businesses are required to obey, on penalty of a gross misdemeanor.

The governor's key emergency powers include:

- authority to declare an energy alert and emergency;
- authority to suspend or modify rules (administrative code);
- authority to suspend or modify standards (such as air quality standards);
- authority to order local governments to implement response programs;
- authority to implement programs, controls, and standards in the production, allocation and consumption of energy resources; and
- authority to establish and implement regional programs.

In developing plans to address an energy emergency, the governor is to give high priority to supplying "vital public services" and, to the extent possible, to encourage and rely on voluntary programs.

The governor is required to state explicitly in the declaration what powers are needed. In addition, extensive and precise language establishes how long emergency powers will exist. Extensions usually require legislative approval.

In August 2000, Governor Locke declared a statewide energy alert and took steps to ensure power for cold storage facilities critical to Washington's fishing and agricultural industries. Bellingham Cold Storage (BCS) provides 40% of the cold storage capacity in western Washington and handles more than a billion pounds of fruits, vegetables, and seafood annually. As a result of a unique set of institutional and regulatory circumstances, BCS found itself exposed to extreme price spikes in the electric market and had curtailed operations, laying off nearly 25% of their workers. As part of the energy alert declaration, the Governor directed the air pollution control authority in Spokane to allow continuous operation of a combustion turbine in Spokane County to provide reasonably priced electricity to BCS. This action allowed BCS to reopen and receive raspberries, cranberries, ocean fish, and other products during the critical summer and fall harvests. [10]

Washington State Energy Emergency Response Plan

Although Washington State has had an electricity curtailment plan and a petroleum contingency plan for many years, the state has had no overall plan on how the state should respond to energy emergencies in general. Energy Division staff is currently drafting a Washington State Energy Emergency Response Plan.

Since each energy shortage is unique, it is impossible to envision every event or combination of events which might qualify as, or lead to, an energy emergency. Instead of developing a separate response plan for every type of shortage, the goal is to develop one flexible plan that would work in any emergency. The Response Plan will provide a management structure which identifies the working relationships among people and a process to make those relationships work in a crisis. The plan will represent a planning process with the flexibility both to evaluate and define a potential emergency, and to respond adequately to any shortage situation.

The Response Plan will rely on a mixed strategy response to an energy shortage. The plan will use a market-based approach with government intervention only to the extent necessary to protect the interests of public health, safety and welfare.

Section I of the Response Plan will provide a description of the phases, coordination with other levels of government, management structure, and mitigation and conservation programs. This section will also indicate the legal authority for the Energy Division to develop and implement an electricity curtailment plan or a petroleum contingency plan.

Section II will describe the plan operations, including the management structure, the organization chart, and operating guidelines or checklists for each person involved in plan implementation.

Section III will contain the office operations of the Energy Division staff under direction of the Energy Division Assistant Director. This section will guide the staff in the areas of data collection and analysis, preparation of reports, implementation of both voluntary and mandatory mitigation and conservation programs, and coordination in economic assistance.

Summary

During the early stages of a shortage, the primary role of state government is monitoring and information exchange, rather than direct intervention in industry efforts to restore services and satisfy customer requirements. The Energy Division serves as a central source of credible and timely information on how a shortage impacts the state as a whole. The goal is to lessen the potential adverse impacts of a shortage by providing the Governor, Legislature, and policy makers, including those at the Military Department's Emergency Management Division, with accurate and timely information for decision making. If the shortage impacts transcend the boundaries of a single service territory or region, or if a shortage is likely to cause public controversy or attract widespread media attention, the Energy Division then intensifies its monitoring and public information activities. If a shortage continues or worsens, the Energy Division will implement voluntary or mandatory conservation and other mitigation programs as appropriate.

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[1] RCW 43.21F State Energy Office Appendix A.

[2] Energy News Data, Western Price Survey, California Energy Markets, November 15, 2000

[3] *Implementation Guide for the Washington State Petroleum Products Contingency Plan,* OTED Energy Division.

[4] *Study of Western Power Market Prices Summer 2000, Final Report*, October 2000. Northwest Power Planning Council document 2000-18.

[5] *Proposed Pacific Northwest Winter 2000-01 Energy Emergency Plan;* NWPP, Pacific Northwest Utilities Conference Committee, Northwest Power Planning Council.

[6] December 8, 2000, *Northwest governors urge conservation as cold spell looms.* http://www.governor.wa.gov/press/press.htm

[7] December 11, 2000, *Locke renews call for energy conservation as cold snap continues.* http://www.governor.wa.gov/press/press.htm

[8] December 12, 2000. Warning of stage two energy alert lifted. http://www.governor.wa.gov/press/press.htm

[9] "A Northwest Power Pool survey discovered that utility and public conservation actions reduced total loads [in the Northwest] by 835 MWh from 5 p.m. to 6 p.m. on December 12….." Clearing Up, December 25, 2000.

[10] Governor's Press Release: *Locke declares energy alert to protect fishing and agriculture industries*, August 10, 2000. http://www.energy.cted.wa.gov/

Governor Locke's Remarks on declaring an Energy Alert at Bellingham Cold Storage, August 10, 2000. http://www.energy.cted.wa.gov/

Declaration of Energy Alert, http://www.governor .wa.gov/eo/energy.htm

CHAPTER 5 GREENHOUSE GAS EMISSIONS AND CLIMATE CHANGE IN WASHINGTON STATE

Consensus is growing in the scientific community that global average temperatures have increased over the last century, with particularly marked increases in the last decade. Scientists have linked these changes to increasing concentrations of greenhouse gases (carbon dioxide, methane, and other gases) resulting from human activities, principally the production and consumption of fossil fuels.

This chapter briefly discusses the possible consequences of global climate change on Washington and the Pacific Northwest, the current scientific basis for climate change, greenhouse gas emissions in the state, and some of the efforts underway both in Washington and other states to reduce greenhouse gas emissions.

Potential Impacts of Climate Change on the Pacific Northwest

What are the likely consequences of global climate change on the state and region? The University of Washington's Joint Institute for the Study of Atmosphere and Ocean (JISAO) completed a study entitled *The Impacts of Climate Variability and Change in the Pacific Northwest*[1] that examined this question.

The JISAO group concluded that "computer models of climate generally agree that the Pacific Northwest will become, over the next half century, gradually warmer and wetter, with most of the precipitation increase in the winter."[2] Among the likely results of such weather pattern changes will be increases in winter flooding and landslides, loss of snow-pack, and more water stress during the summer months.

From an energy perspective, the impacts of climate change on hydrology and hydroelectric generation are likely to be significant. The study concludes that "warmer, wetter winters and hotter summers will reduce winter snowpack, increase winter runoff and flooding, change the spring freshet for migrating juvenile salmon, and reduce summer water supply and water quality."[3] Both the Northwest and Washington State are highly dependent on winter snowpack for water storage. Declining storage will mean less water available for the already competing uses of fish, hydroelectricity, irrigation, municipal and industrial water supply, and recreation. Current demand for low cost Columbia/Snake River generated electricity already outstrips supply. Change in the timing and decreases in the availability of snowmelt could lead to further significant declines in this supply.

Climate Science - Increasing Scientific Consensus

Scientific investigation of global climate change is a coordinated effort by the Intergovernmental Panel on Climate Change (IPCC). The World Meteorological Organization and the United Nations established the IPCC in 1988 as a response to growing concerns about human caused climate change. The IPCC role is to "(i) assess available scientific information on climate change, (ii) assess the environmental and socio-economic impacts of climate change, and (iii) formulate response strategies"[4] The Panel's oft quoted 1995 conclusion about man-made greenhouse gas emissions and global climate change was that "the balance of evidence suggests a discernable human influence on global climate," and that such influence was likely to result in a 1 to 3.5 degree centigrade increase in global average temperatures by 2001.

An updated version of the 1995 report will be published in 2001. A draft of this update was issued in October 2000 for governmental review. Robert Watson, Chair of the IPCC, presented a summary on the current state of knowledge on climate change at the recently concluded climate meeting in The Hague.[5] Watson underscored the basic conclusions of the IPCC, "[t]he overwhelming majority of scientific experts, whilst recognizing that scientific uncertainties exist, nonetheless, believe that human-induced climate change is inevitable." He further noted that global mean surface temperatures are projected to increase by about 1.5 to 6.0°C (2.7 to 10.8°F), nearly a doubling of the estimates made in 1995. The higher temperature projections result from new analyses indicating that air pollution control efforts will decrease atmospheric aerosols, which create an atmospheric cooling effect. Such warming, if unchecked, would be at a rate unprecedented in the last 10,000 years.

Greenhouse Gas Emissions in Washington State

Carbon dioxide emissions from energy use are determined by the quantity of fossil fuels consumed and their carbon content. Figure 18 shows carbon dioxide emissions by end use sector since 1960[6]. Emissions are calculated for each fossil fuel consumed or sold in the state. The building sector includes the residential and commercial sectors while the electricity sector includes utility and non-utility emissions. Emissions for 2000 are annualized emissions based on preliminary reports through August 2000. Washington's emissions profile differs from the national average because our traditional source of electricity was hydroelectricity. This results in the transportation sector being responsible for most of the emissions. On a relative basis, transportation emissions have risen from 42% of the total in 1960, peaked in 1995, and have declined slightly in the late 1990's. However, on an absolute basis emissions, are increasing in all sectors.

Figure 18 dramatically shows the influence of changes in fuel use. The emissions from the generation of electricity increased dramatically in 1972 when the Centralia (now TransAlta) power plant came on line and began consuming large quantities of coal. Since the mid-1990's utilities and non-utility companies have begun using natural gas in combustion turbines to supply growing demand for electricity. Carbon dioxide emissions from the electricity sector are now greater than those from fossil fuel use in the industrial or buildings sectors. Emissions from the electric sector are estimated to be at a record high of 17 million tons of carbon dioxide in 2000. If all the power plants that are currently proposed came on line an additional 18.5 million tons would be emitted.[7] Figure 24, in Chapter 6, charts CO_2 emissions by type of fuel rather than end use. Over 75% of CO_2 emissions are from petrol-eum consumption, primarily for transportation.

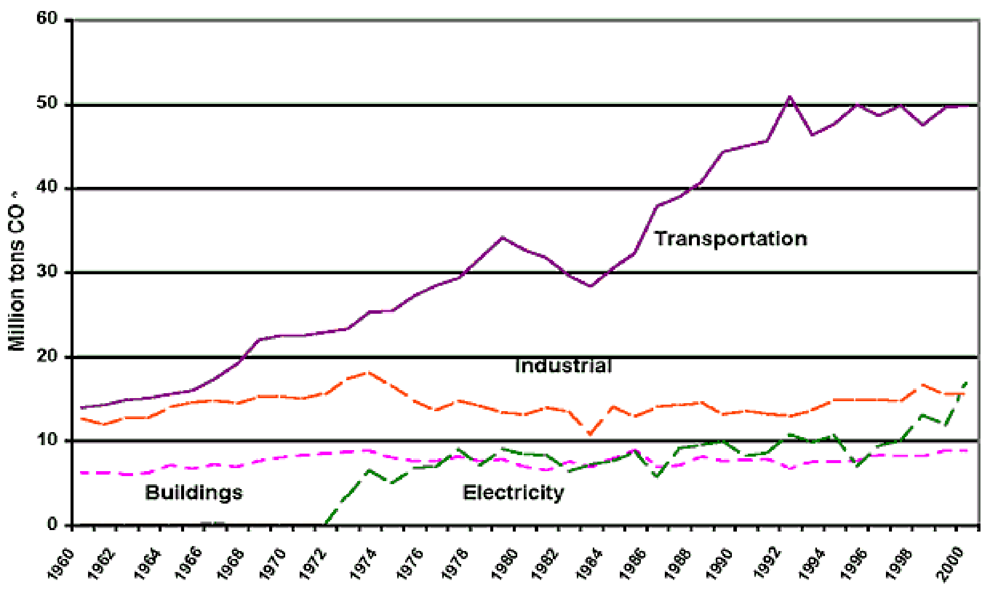

Figure 18 CO_2 Emissions from Fossil Fuel Consumption

Source Energy Information Administration Data

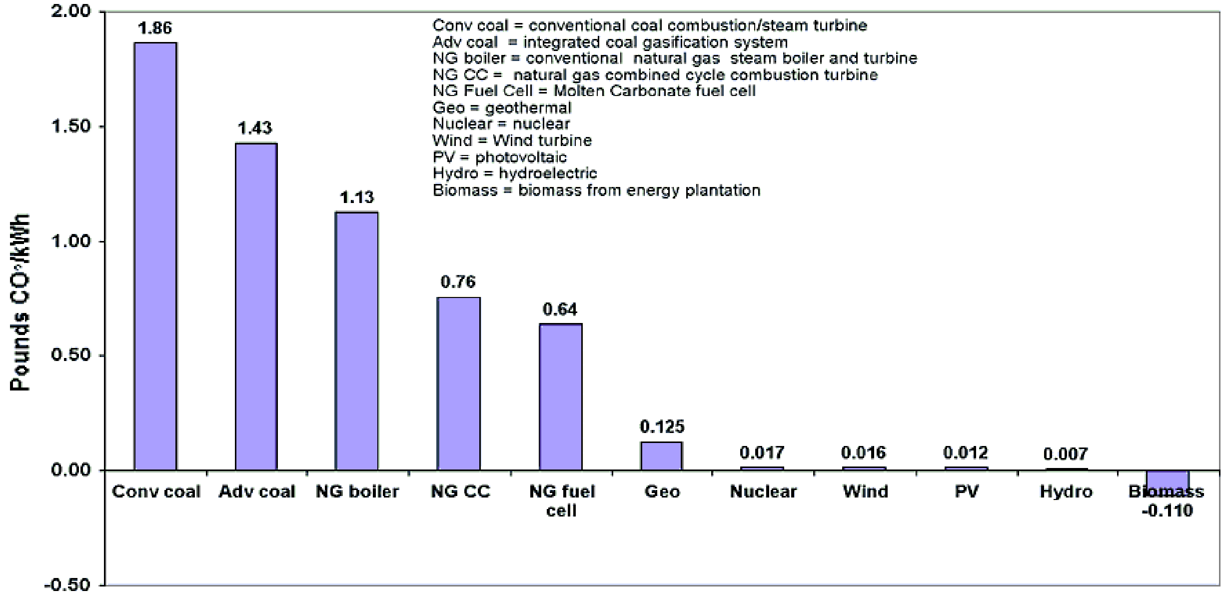

Figure 19 CO_2 Emissions by Electric Generating Technology and Fuel Source

Source: Energy Information Administration, Department of Energy

Emissions from electric generating facilities depend on both the technology and the fuel choice. The technology determines the efficiency of converting the fuel into electricity and the fuel determines the carbon content. Figure 19 illustrates the wide range of carbon dioxide emissions from electric generation[8]. The renewable and nuclear options have no net emissions from fuel use and are an order of magnitude lower than emissions from fossil generation. The small quantities shown account for the emissions resulting from the materials used to construct the facilities. The biomass emissions are shown as negative based on the assumption that energy plantations would provide the fuel and that they result in a net sequestration (storage) of carbon dioxide.

Carbon Sinks

Most discussion on greenhouse gases deal with emissions. The Kyoto protocol recognized that carbon dioxide concentrations in the atmosphere were the critical factor in driving climate change. The global carbon cycle is characterized by large natural fluxes into and out of oceans and vegetation. These fluxes result in a small net sink that partly compensates for fossil fuel emissions. The Kyoto protocol suggests that management of natural terrestrial carbon sinks, primarily afforestation[9] and reforestation at a global scale, can increase sink strength and thus reduce atmospheric carbon dioxide concentrations.

There are many unanswered questions concerning the accounting for carbon sinks. One of these questions is how do we actually measure the quantity of carbon sequestered and another question is how long the carbon will be kept out of the atmosphere. The advocates of carbon sequestration point out that it is often one of the lowest cost options for reducing net emissions and it may result in more sustainable management of our forest and agricultural lands. This issue is currently being discussed in international negotiations. The Washington legislature has considered several bills dealing with carbon sequestration over the last few years.[10] Their intent was to develop a Washington State carbon sequestration implementation and certification plan. So far, no bill has been sent to the Governor.

State Policy Actions and Options for Greenhouse Gas Reduction

Most of the discussions of climate change, greenhouse gas reduction, and response have centered on national and international actions. Will the U.S. Senate ratify the Kyoto climate accord? How should an international carbon trading program function? What are the appropriate obligations of developing nations?

Yet, many of the most innovative and effective greenhouse gas reduction and climate response actions are occurring at the state level. This section describes some of the activities underway in Washington and other states.

Washington's Response

Washington State has few specific policies or programs in place at the state level to address climate change or greenhouse gas mitigation. Efforts in the 1999 and 2000 legislative sessions to pass legislation that would set up task forces to investigate climate change impacts on Washington State, encourage carbon storage (sequestration), or support greenhouse gas reduction efforts were all unsuccessful.[11] Nonetheless, there are a number of policy, education, and program activities underway throughout the state to decrease greenhouse gas emissions.

Three Washington cities (Seattle, Burien, and Olympia) are members of the International Council for Local Environmental Initiatives (ICLEI) Cities for Climate Protection's Campaign. One example of what these Washington cities are doing is Seattle's ambitious attempt to cut greenhouse gas emissions. In April 2000, Seattle adopted a resolution that established " a long-range goal of meeting the electric energy needs of Seattle with no net greenhouse gas emissions."[12] In order to implement this resolution Seattle City Light has issued a request for proposal for 100 average megawatts of new generating resources from renewable, non-carbon sources (biomass, geothermal, hydro-electric, solar, landfill, and wastewater treatment gas, or wind generation). This is one of the largest efforts to bring on new renewable energy resources by any utility in the Northwest. Seattle expects to have contracts in place for these resources in early 2001.

Many prominent Washington companies have joined voluntary national efforts to improve energy efficiency, increase environmental quality, and reduce their greenhouse gas emissions. Boeing, Starbucks Coffee, and Associated Grocers are among more than 30 Washington-based companies that are members of EPA's Climate Wise Program.[13] Each of these companies has developed action plans and implemented measures to reduce their energy use and consequently, their greenhouse gas emissions. In addition, Boeing, Weyerhaeuser, DuPont, Enron, Shell, and 17 other multinational corporations are members of the Pew Center's Business Environmental Leadership Council. Membership in the Council includes recognition that "the views of most scientists that enough is known about the science and environmental impacts of climate change for us to take actions to address its consequences." And, further, that "We can make significant progress in addressing climate change and sustaining economic growth in the United States by adopting reasonable policies, programs and transition strategies."[14]

Several Washington State-based nonprofit organizations are actively involved in efforts to increase awareness of global climate change, its impacts on the Northwest, and ways to reduce greenhouse gas emissions. The Northwest Council for Climate Change, working in conjunction with Washington State University, OTED, and Climate Solutions, recently completed a series of presentations to local governments, chambers of commerce, and civic organizations throughout the state focusing on climate change in the Northwest. Climate Solutions, an Olympia-based nonprofit works with government, businesses, and trade associations on ways to encourage clean energy development (renewable energy and energy conservation) that decreases greenhouse gas emissions while generating new or expanded opportunities for economic development.[15]

Finally, on December 5, 2000, the Energy Facility Site Evaluation Council (EFSEC) issued an initial order that would require the proposed 520-megawatt Chehalis Generating Station to offset a portion of its lifetime CO_2 emissions.[16] The amended site certification agreement would require Chehalis power to develop a plan to offset greenhouse gas emissions from the plant. Chehalis' offsets must be based on the Oregon Carbon Dioxide Emission Standard (see next section) which is equivalent to an approximately 17% reduction in lifetime CO_2 emissions from the plant. Chehalis would be required to make payments to EFSEC, over a five-year period, to fund the offset projects.[17] As of the publication of this report, the initial order had not been finalized and sent to the governor for his approval, denial, or remand.

Policies and Actions in Other States

There are numerous ways that other states have directed policies and actions toward greenhouse gas reductions. Below are a few representative examples of greenhouse gas reduction planning and target setting, state tax incentives, electric utility support for public purposes (conservation, and renewable energy development), and greenhouse gas reduction standards for new electric generating facilities.

Statewide Greenhouse Gas Reduction Goal Setting

Several states have established goals for overall reduction in greenhouse gas emissions. One of the more recent and ambitious efforts is New Jersey's Sustainability Greenhouse Gas Action Plan.[18] New Jersey's greenhouse gas efforts are part of a larger effort by the state to pursue policies that support sustainability as required under Executive Order 96.[19] New Jersey's focus on global warming and greenhouse gas reductions come from growing concerns about the impacts of sea level rise on the state's environment and economy.

New Jersey's greenhouse gas action plan focuses on five categories of mitigation: 1) energy conservation, 2) innovative technologies, 3) pollution prevention, 4) waste management (municipal solid waste landfill gas recycling), and 5) natural resources-open space. The goal of the plan is to reduce CO_2-equivalent emissions by 20.4 million tons by 2005 - a 3.5 % reduction from 1990 levels.

Tax Incentives

The State of Maryland has recently instituted a wide range of tax incentives to encourage energy efficiency and development of renewable resources

The Maryland Clean Energy Incentive Act, which went into effect on July 1, 2000, provides Maryland sales tax exemptions when purchasing qualifying high efficiency Energy Star appliances, electric and hybrid-electric vehicles, and certain renewable resource energy systems.[20] Solar heating and photovoltaic systems along with electric and hybrid vehicles qualify for significant income tax or excise tax credits.

Public Benefits from the Electricity Sector

Nearly half of the states have introduced some form of electric industry restructuring. Many of those states have recognized the continuing societal benefits of investments in energy efficiency and renewable energy development while also acknowledging that a more open and competitive electricity industry structure may not provide sufficient support for these common public goods. States have responded to this discontinuity by instituting a variety of support mechanisms for conservation and renewables including systems benefit charges and renewable portfolio standards.

California recently reauthorized its Systems Benefit Charge (SBC) through 2011 (SB 1194, passed in September 2000). The extension of the SBC provides for continued funding of cost-effective energy efficiency and conservation, public interest research and development, and support for existing, new, and emerging renewable energy technologies. Funding for these efforts is derived from a 3% assessment on retail electricity sales from investor-owned utilities. Although California public benefits programs were not primarily designed to reduce greenhouse gas emissions, significant reductions are a likely consequence.

In the Northwest, the Northwest Power Planning Council (NWPPC) convened a regional technical forum (RTF) to establish eligibility standards for Bonneville Power Administration's conservation and renewable energy discount program. The RTF concluded "there is at the very least a risk that serious damage will result from continued increases in greenhouse gas concentrations in the atmosphere." Consequently, they assigned a $15 per ton of CO_2 benefit to be added to the avoided cost calculation for new electricity generation, thus increasing the value of both electricity conservation and generation of electricity from renewable sources.[21]

Regulation of Power Plant Emissions of CO_2

Two other states impose regulations requiring developers of new electric generating plants to offset a portion of the CO_2 emissions from those facilities. Since 1993, the state of Mas-sachusetts, through its Energy Facility Siting board, has required new power plants to offset from 1% to 3% of the plant's total CO_2 emissions at a rate of $1.50 per ton of CO_2. Massachusetts estimates that plants nearing completion will generate approximately $3 million to fund cost effective CO_2 mitigation projects (most likely reforestation efforts)[22]

Oregon has the most stringent requirement for greenhouse gas reductions for newly sited power facilities.[23] The Oregon statute requires that all new baseload natural gas-fired combustion turbines must offset their carbon dioxide emissions to a level of 0.675 lbs. CO_2/killowatt hour. In effect, this standard requires plants to offset their greenhouse gas emissions by 17%. Since there is no cost-effective method to remove carbon dioxide from the plant's stacks, this requirement is met by a combination of greenhouse gas reductions through energy conservation and carbon storage (sequestration) through forestry and agricultural practices. In addition, Oregon has created the Climate Trust as a recipient of mitigation funds. Oregon has sited three new generating facilities that have met this requirement.

Conclusion

There is significant scientific agreement that human-induced climate change is a real phenomenon. Unchecked climate change could have important negative consequences for the Northwest and Washington State. Fortunately, there are many actions and policies available to states that can decrease greenhouse gas emissions while maintaining or even enhancing environmental quality and economic well being.

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[1] JISAO Climate Impacts Group, University of Washington, *The Impacts of Climate Variability and Change in the Pacific Northwest,* November 1999.

[2] IBID, Overview.

[3] IBID, p 44.

[4] Houghton, J. T. (ed.) *Climate Change 1995, The Science of Climate Change,* Cambridge Press, 1996, Forward.

[5] Presentation of Robert T. Watson, Chair, Intergovernmental Panel on Climate Change, at the Sixth Conference of the Parties to the United Nations Framework on Climate Change, November 13, 2000.

[6] *U.S. Energy Information Administration (EIA), State Energy Data Report 1997 for 1960-1997, for 1998-2000,* various EIA Annual and monthly reports.

[7] From WIEB showing 5,800MW of new natural gas generation and assuming a 90% capacity factor and 0.81 lb. CO_2/kWh.

[8] EIA *Annual Energy Outlook 1999 and US Department of Energy, Environmental Emissions from Energy Technology Systems: The Total Fuel Cycle,* 1989.

[9] IPCC defines afforestation as" planting of new forests on lands which, historically, have not contained forests" and reforestation as "planting of forests on lands which have, historically, previously contained forests but which have been converted to some other use".

[10] For example, SB5121, Establishing a Carbon Storage Program, 2000.

[11] For example, SB 2518, Creating a Joint Select Committee on Climate Change, 2000/

[12] City of Seattle, Resolution 30144, April 3, 2000.

[13] See http://www.ci.seattle.wa.us/light/conserve/business/cv5_cw.htm for information on what these companies have accomplished and what additional actions they plan to undertake.

[14] http://www.pewclimate.org/belc/index.cfm, November 12, 2000.

[15] See for example Patrick Mazza, *Accelerating the Clean Energy Revolution: How the Northwest Can Lead,* Climate Solutions, April 2000.

[16] EFSEC, Council Order No. 752, *Findings of Fact, Conclusions of Law, and Initial Order Granting Amendments on Condition,* December 5, 2000.

[17] Energy Facility Site Evaluation Council, Draft Amended Site Certification Agreement Between the State of Washington and the Chehalis Power Generating, Limited Partnership for the Chehalis Generation Facility, as amended by Amendment No. 1, December 5, 2000.

[18] New Jersey Department of Environmental Protection, *Sustainable Greenhouse Action Plan,* December 1999.

[19] IBID, Appendix A.

[20] "The Maryland Clean Energy Incentive Act" more information is available at http://www.energy.state.md.us/incentive.htm.

[21] Northwest Power Planning Council, RTF Final Recommendations to the Bonneville Power Administration on the Conservation and Renewable Discount - August 21, 2000

[22] Sonia Hamel, "CO_2 Mitigation in the Siting of Power Plants," presentation at the EPA 4th State and Local Climate Change Partner's Conference, Arlington, VA, November 3, 2000.

[23] Oregon Revised Statutes (ORS) 345-024-0500 Standards for Energy Facilities That Emit Carbon Dioxide.

CHAPTER 6 ENERGY INDICATORS

Contents

Introduction

Energy is a critical component of every aspect of Washington's economy and is used daily by every resident of the state to meet the most basic human needs. Energy lights and heats our homes, cooks our food, fuels our vehicles, and powers our industries. But few of us have a thorough understanding of key trends taking place in this crucial industry. This section presents a series of 24 “Energy Indicators”, illustrating some of the most important long-term energy trends. Each indicator consists of a chart based on readily available energy, economic, and demographic information, a caption highlighting key trends depicted in the chart, and narrative giving additional perspective or describing further aspects of the indicator.

This is the first update of the Energy Indicators, which were first published in 1999 as part of the 1999 Biennial Energy Report. The Indicators began as a successor to the *Washington State Energy Use Profile*, which was published periodically in the past by the Washington State Energy Office, most recently in June of 1996. The Indicators combine energy, economics and demographic data into a series of charts and graphs, each of which portrays a distinct view of Washington’s energy picture.

In order to ensure that the Energy Indicators presented here are grounded in the best available information and can be updated on a regular basis, they are based exclusively on regularly published data from sources in the public domain. The U.S. Energy Information Administration (EIA) has the most complete sources of annual, state-level energy data. Our principal source is the EIA’s Combined State Energy Data System (CSEDS), the database used to publish the State Energy Data Report (SEDR) and the State Energy Price and Expenditure Report (SEPER). Additional sources are listed at the end of this chapter.

Collecting and publishing detailed statistics on energy consumption, price, and expenditures for fifty states and the District of Columbia is a large task produced after work done on fuel-specific data, thus comprehensive state information from EIA lags by two to three years. Consequently, the Energy Indicators are confined to analysis of long-term energy trends. The impacts of the dramatic increases in the market prices of electricity and natural gas that occurred during the second half of 2000 are discussed in other chapters of this report, and will be addressed in future versions of Washington’s Energy Indicators.

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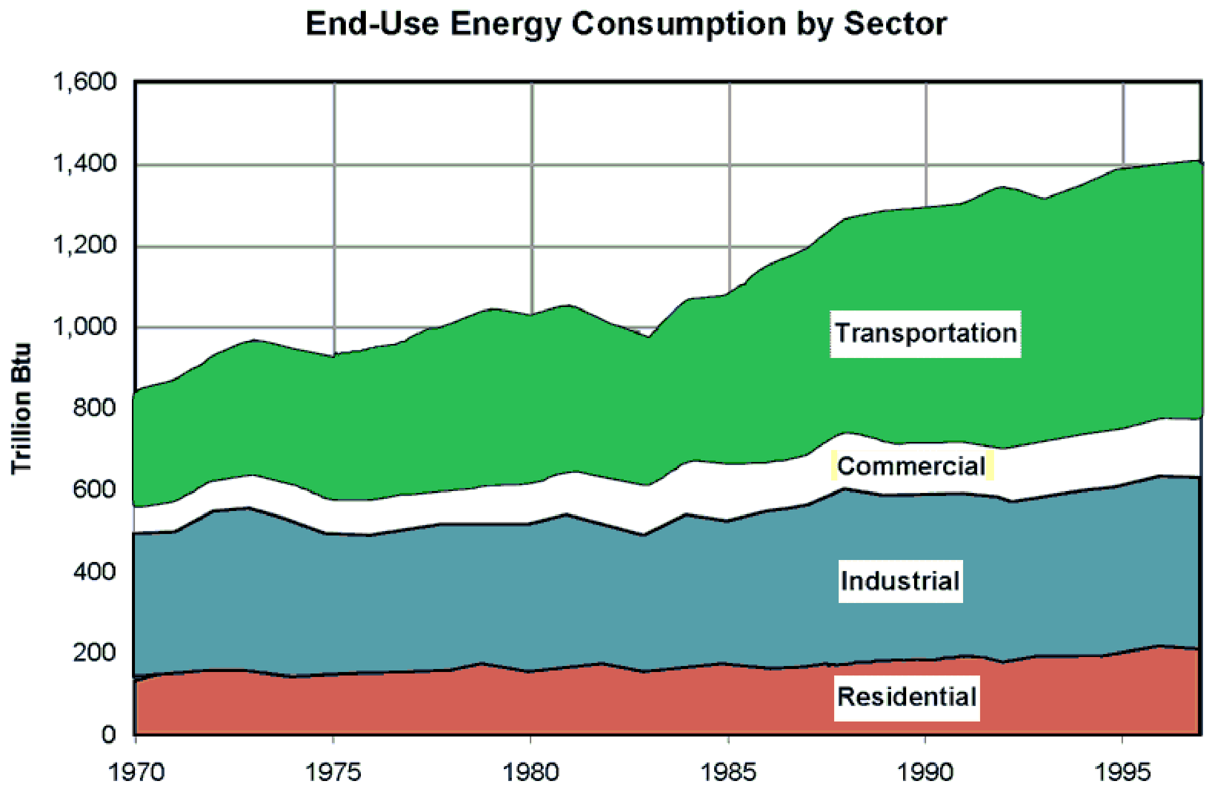
1. Washington's Energy Use — End-Use Energy Consumption



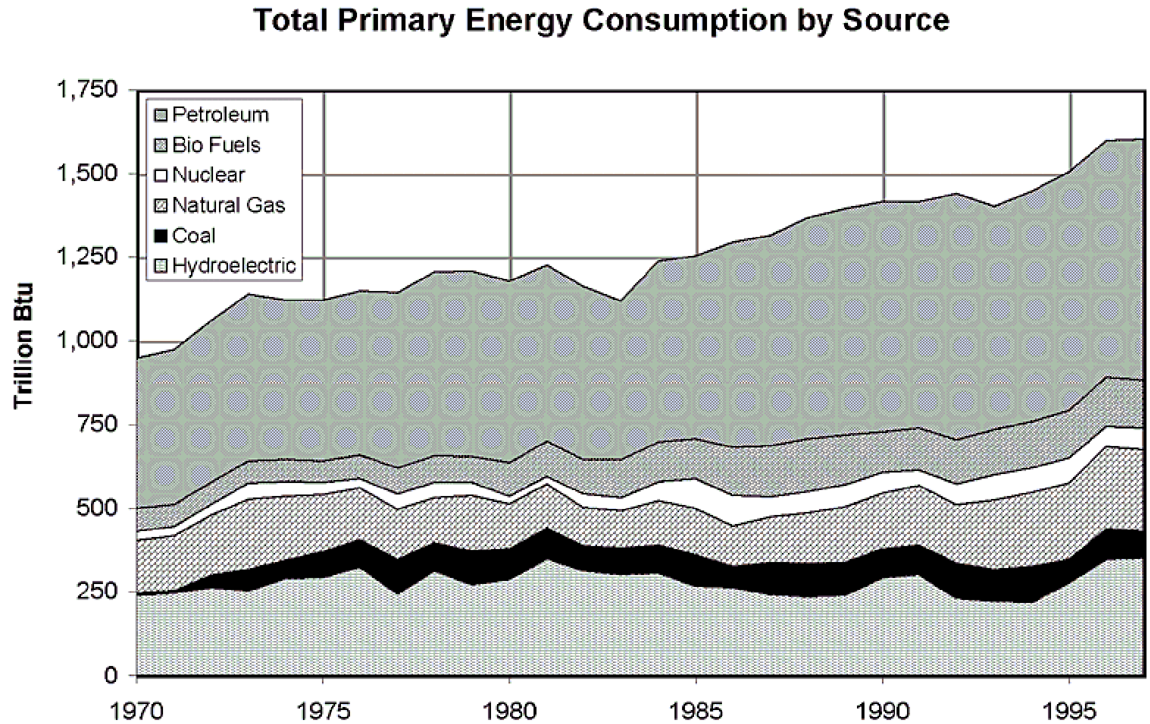
END USE ENERGY CONSUMPTION IN WASHINGTON WAS TWO-THIRDS HIGHER IN 1997 THAN IN 1970. MOST OF THE INCREASE OCCURRED IN THE TRANSPORTATION SECTOR, WHERE ENERGY USE HAS MORE THAN DOUBLED SINCE 1970. TRANSPORTATION NOW ACCOUNTS FOR CLOSE TO HALF OF THE STATE'S ENERGY CONSUMPTION.

Washington's end-use energy consumption grew at 1.3% per year between 1993 and 1997, reaching an all-time high of 1.4 quadrillion Btu in 1997. The transportation sector accounts for the largest share of growth in energy consumption, growing at an annual rate of 3.7% since 1985.

During the 1970s and early 1980s, growth in energy consumption was dampened by higher energy prices and changes in the state's economy. Industrial sector energy consumption was nearly flat between 1970 and 1985. Energy consumption in the commercial sector, which includes service industries such as software, finances and insurance, more than doubled over the same period, but remains small relative to other sectors.

The period since 1985 has been characterized by modest growth in the residential and industrial sectors, where energy consumption grew at 1.5% per year between 1985 and 1997, and rapid growth in the transportation sector of 3.7% per year. After spiking in the late 1970s and early 1980s, energy consumption in the commercial sector has been nearly flat since 1985.

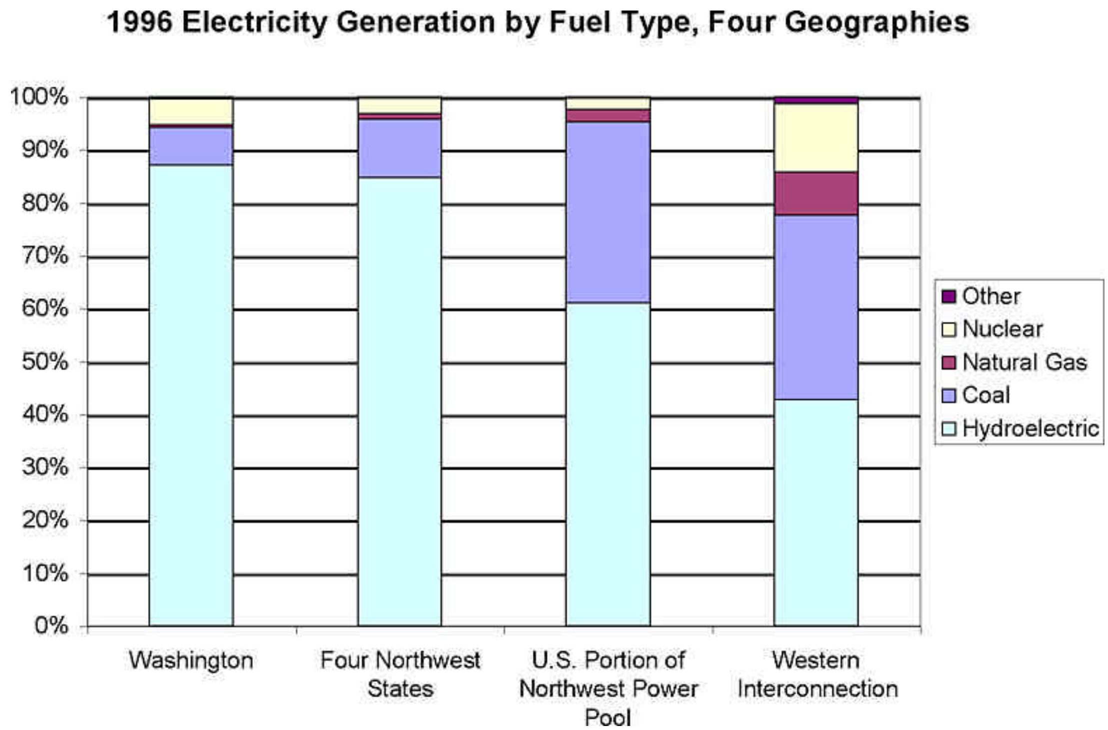
2. Washington's Energy Use — Primary Energy Consumption



WASHINGTON CONTINUES TO RELY ON PETROLEUM FUELS TO MEET ABOUT HALF ITS ENERGY NEEDS. THE RELATIVE CONTRIBUTION OF HYDROELECTRICITY AS AN ENERGY SOURCE HAS DECLINED[1].

This indicator shows the extent of Washington's reliance on six major primary[2] energy sources: petroleum, hydroelectricity, natural gas, biofuels, coal, and uranium. Washington continues to rely on petroleum, more than three-quarters of which is imported by tanker from Alaska, to meet 45% of its primary energy needs. This share has not changed appreciably since 1970. Hydroelectricity's relative importance has declined since the mid 1980s; while total generation from hydroelectric dams has stayed relatively constant, consumption of fossil fuels has grown rapidly. Natural gas consumption doubled between 1983 and 1995, regaining the market share it lost during the 1970s. Natural gas now accounts for nearly 15% of Washington's primary energy consumption. Biofuels, mainly wood and wood waste products, account for 8% of primary energy consumption. These fuels are primarily burned for steam and cogeneration at pulp and paper mills. Coal is consumed almost exclusively at the Centralia Steam Plant, while uranium is used at the Energy Northwest's Columbia Generating Station plant in Richland. Together, coal and nuclear generation accounted for 9% of Washington's primary energy supply in 1997.

3. Washington's Energy Use — Electricity Generation



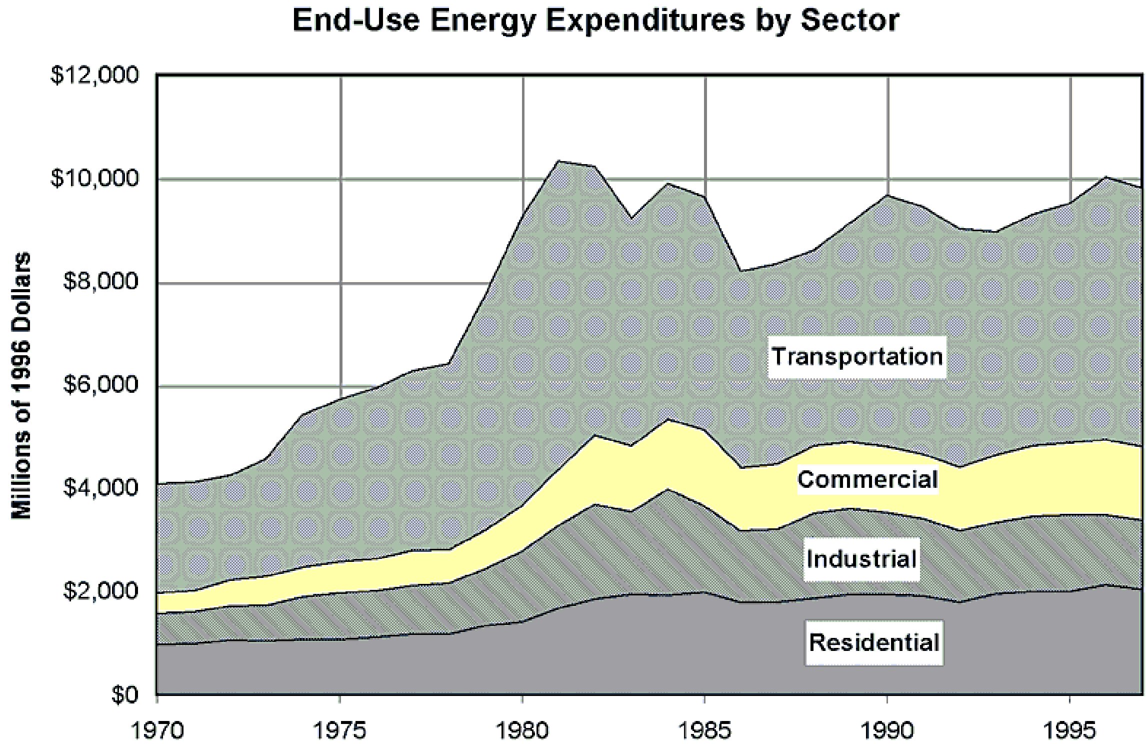
WHILE 85% OF ELECTRICITY GENERATED IN WASHINGTON COMES FROM HYDROELECTRIC DAMS, WASHINGTON CONSUMERS ARE SERVED BY ELECTRICITY FROM GENERATING PLANTS LOCATED THROUGHOUT THE WESTERN INTERCONNECTION. MANY OF THESE PLANTS ARE FIRED BY COAL OR NATURAL GAS.

How much of Washington's electricity is hydro? The answer depends on how one defines "Washington's electricity". While hydroelectric dams accounted for 85% of the electricity generated in Washington in 1996, Washington is part of an interconnected, regional bulk power system and Washington consumers are dependent on coal, natural gas, and nuclear plants in other states. Moreover, much of the hydroelectric generation in Washington is owned by the federal government and operated on behalf of customers in multiple states.

A better proxy for "Washington's electricity" might be the mix of generation in the U.S. portion of the Northwest Power Pool (NWPP.)[1.] This incorporates coal plants in Oregon, Montana, Wyoming, and Utah owned by utilities that serve Washington customers. Hydroelectric dams accounted for 61% of NWPP generation in 1996, while 34% came from coal-fired plants.

However, this still ignores seasonal purchases and exchanges of nuclear, coal, and gas-fired electricity from the Southwest. The 1996 generation mix for the U.S. portion of the Western Interconnection[2] was 43% hydro, 35% coal, 13% nuclear, and 8% natural gas.

4. Washington's Energy Bill — End Use Energy Expenditures

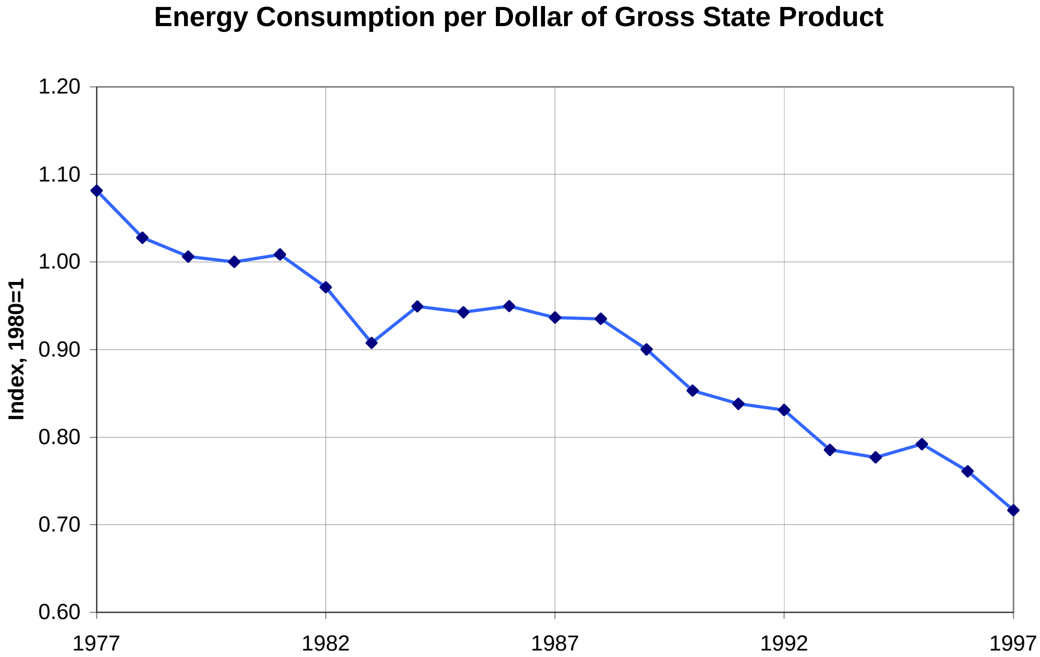


ADJUSTED FOR INFLATION, ENERGY EXPENDITURES IN WASHINGTON IN 1997 WERE JUST 6% HIGHER THAN IN 1980, DESPITE A 37% INCREASE IN ENERGY CONSUMPTION DURING THAT PERIOD.

Washingtonians spent $9.8 billion on energy in 1997. While that represents a 60% increase over 1980 in nominal terms, when adjusted for inflation the amounts are very similar, despite a 37% increase in energy consumption. Energy prices have not kept pace with inflation since oil and gas prices peaked in the early 1980s. This period contrasts sharply to the 1970s, when expenditures on energy increased by 150% in real terms.

The transportation sector accounts for the largest share of energy expenditures, 45% in 1997. This proportion declined, however, from over 60% in 1980, even as transportation's share of statewide energy consumption increased. The real price of petroleum fuels declined significantly between 1980 and 1997, while the price of electricity, the largest energy source in the residential and commercial sectors, stayed constant.

5. Washington's Energy Intensity — Energy Consumption per Dollar of Gross State Product

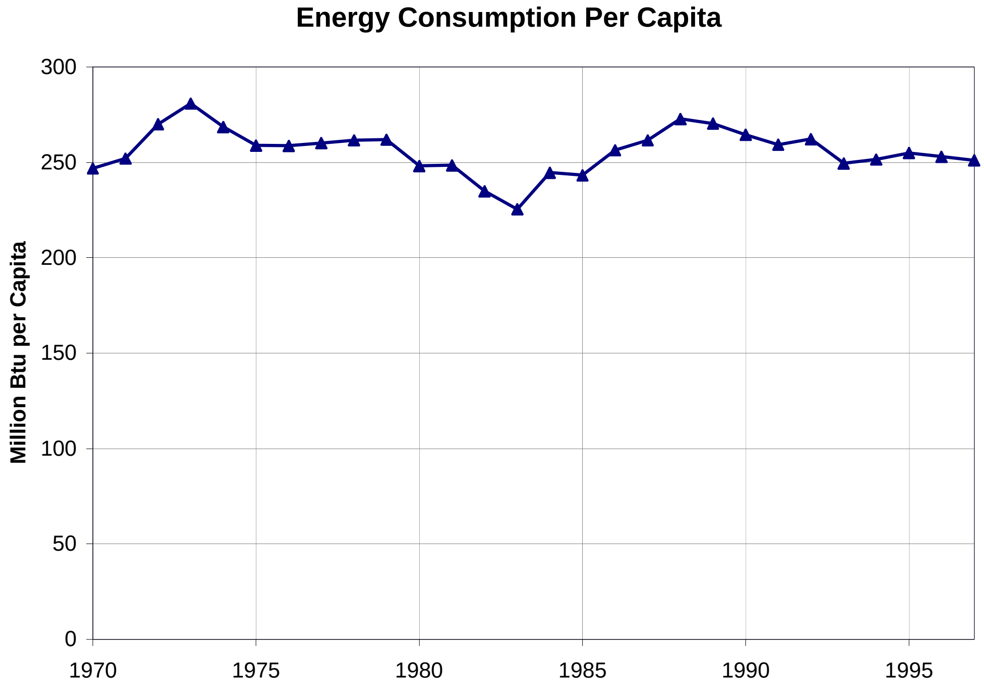


WASHINGTON CONTINUES TO PRODUCE MORE REAL VALUE IN GOODS AND SERVICES PER UNIT OF ENERGY CONSUMED, DESPITE GROWTH IN TOTAL ENERGY CONSUMPTION. KEY REASONS ARE A SHIFT IN THE STATE'S ECONOMY TO HIGH-VALUE BUSINESSES THAT ARE LESS ENERGY-INTENSIVE AND IMPROVED PROCESS EFFICIENCY.

This measure of the overall energy intensity of Washington's economy depicts the amount of energy we use to produce a dollar's worth of economic output. Washington energy consumption is divided by real Gross State Product (GSP), the sum of all goods and services produced in the state, and the result is indexed so that the value in 1980 is equal to one. Despite the rapid increase in Washington's total energy consumption between 1980 and 1997, energy consumption per dollar of GSP declined by 28% over the period.

Washington's economy is growing faster than its energy consumption, and has been since at least 1977, when the Gross State Product data series we use begins. This is due to a number of factors, chief among them a shift in the state's economy from resource and manufacturing industries to commercial activity based on software, biotech, and other, less energy intensive businesses. Gains in energy efficiency have also contributed.

6. Washington's Energy Intensity — Energy Consumption per Capita

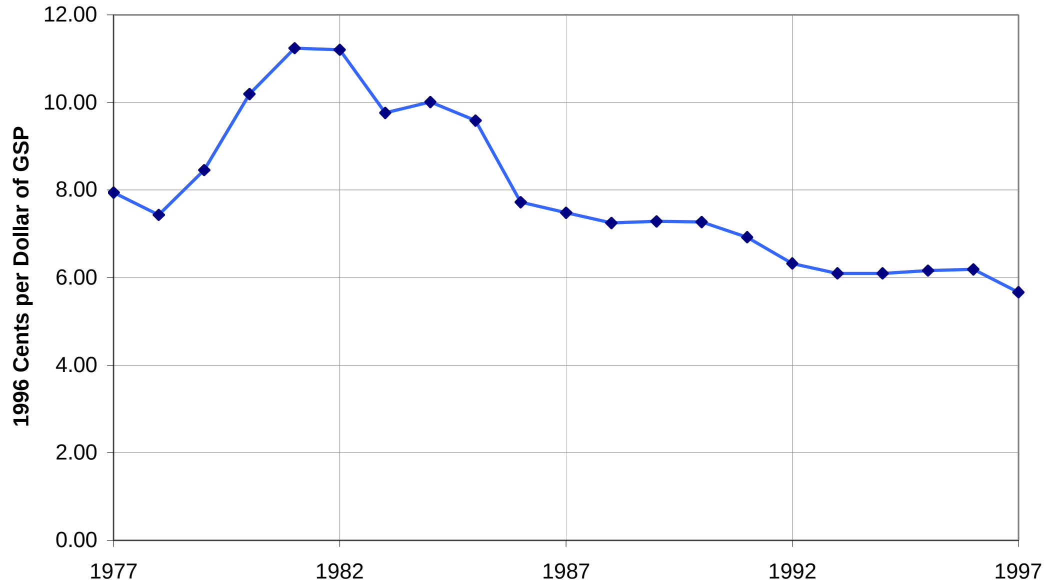


ENERGY CONSUMPTION PER CAPITA IS SIMILAR TODAY TO LEVELS IN 1970. EXCEPT AT THE DEPTHS OF THE EARLY-1980S RECESSION, ENERGY CONSUMPTION PER CAPITA IN WASHINGTON HAS STAYED RELATIVELY CONSTANT SINCE THE 1970S.

Another way to look at Washington's energy intensity is energy consumption per capita. While the previous indicator demonstrated that Washington continues to create more wealth per unit of energy, here the story is somewhat different. Washington's per capita energy consumption in 1997 was 250 million Btu. That's the equivalent of about 2000 gallons of gasoline per person, and is identical to the figure for 1971. Energy consumption per capita declined by about 25% between 1973 and 1983, to a low of 225 million Btu per person in 1983. This was followed by a period of rapid growth between 1983 and the end of the decade. Most of the increase occurred in transportation fuels, as communities began to sprawl and Washingtonians drove more and more miles per year. Per capita energy consumption was relatively flat through the first eight years of the 1990s.

7. Washington's Energy Intensity — Energy Expenditures and Gross State Product

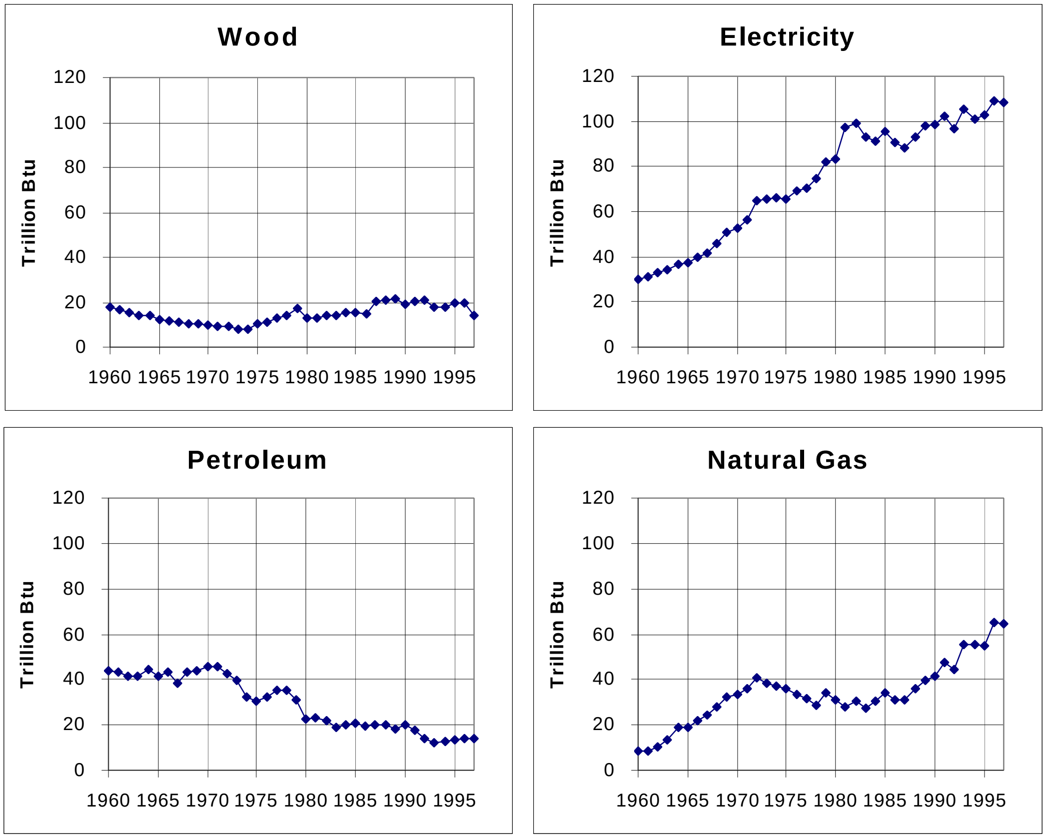
Energy Expenditures per Dollar of Gross State Product



ENERGY EXPENDITURES ARE DECLINING RELATIVE TO ECONOMIC OUTPUT, DESPITE GROWTH IN ENERGY CONSUMPTION[1]. PRINCIPAL CAUSES ARE DECLINING ENERGY INTENSITY AND LOWER ENERGY PRICES.

This indicator divides statewide energy expenditures by economic output, in the form of Gross State Product. The result is an estimate of the significance of energy in Washington's economy. Approximately 5.6¢ is spent on energy in Washington for every dollar of gross state product. This number has been declining steadily since peaking at 11¢ in 1981. Two trends have contributed to this decline: Washington's economy is becoming less energy-intensive and real energy prices have declined. In 1997, energy expenditures were smaller relative to Washington's economy than at any time in history.

8. Residential Sector Trends — End-Use Energy Consumption by Fuel

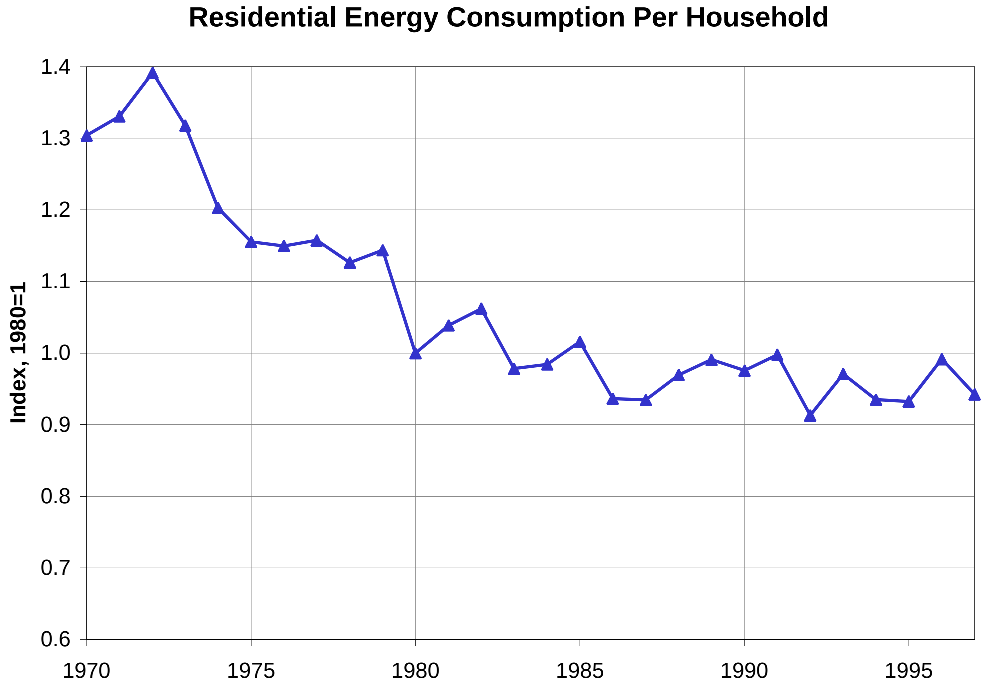


GROWTH IN HOUSEHOLD ELECTRICITY CONSUMPTION HAS SLOWED IN THE LAST 16 YEARS, WHILE GROWTH IN NATURAL GAS USE HAS ACCELERATED. OIL CONSUMPTION CONTINUES TO DECLINE,[1] BUT NEW ESTIMATES INDICATE SURPRISING STABILITY IN WOOD USE.

Electricity accounts for the majority of residential energy consumption, but average electricity use per household has declined since 1980. Growth in natural gas consumption has accelerated; residential sector gas use grew at 1.9% per year between 1980 and 1985, 3.9% per year between 1985 and 1990, and 6.5% per year between 1990 and 1997. Propane use has grown considerably in recent years as well, but is masked here by the decline in heating oil, which fell from more than 43% of household consumption in 1960 to less than 7% in 1997.

Consumption of firewood grew in the late 1970s in response to high heating oil prices. Despite environmental restrictions and the increasing popularity of gas appliances, estimates of wood consumption have remained remarkably high and stable since rising again in the late 80's.

9. Residential Sector Trends — Household Energy Intensity

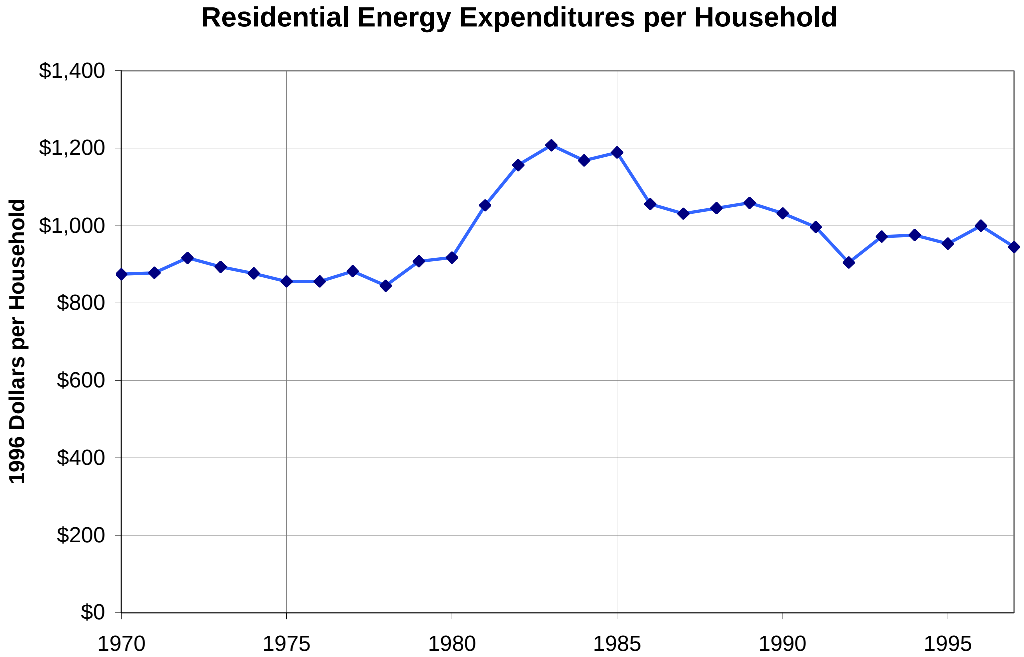


ENERGY CONSUMPTION PER WASHINGTON HOUSEHOLD HAS DECLINED BY ALMOST A THIRD SINCE PEAKING IN 1972, INDICATING AN IMPROVEMENT IN HOUSEHOLD ENERGY EFFICIENCY. GAINS HAVE SLOWED IN RECENT YEARS.

Washington households became much more energy efficient between 1970 and 1985, with a slower decline since. The 1970s were characterized by diminished oil and natural gas consumption, with natural gas use per household falling by 33% between 1970 and 1980. Oil consumption dropped from 300 gallons per household in 1970 to 85 in 1983, with half the decline occurring after the second oil shock in 1978. The data indicate an increased reliance on wood and electricity as space heating fuels during the late 1970s and early 1980s. Concerted efforts to improve residential efficiency through building standards and codes began in earnest in the mid-80s. Despite larger houses, more widespread use of air conditioning, and the significant proliferation of electricity-using appliances, electricity consumption per household declined by 7% between 1985 and 1997.

The trend toward lower household energy consumption has slowed recently, as declines in wood and petroleum consumption during the 1990s have been offset by increasing natural gas consumption. Moreover, these data do not include energy used for personal transportation, which has increased markedly during the last fifteen years.

10. Residential Sector Trends — Household Energy Bill



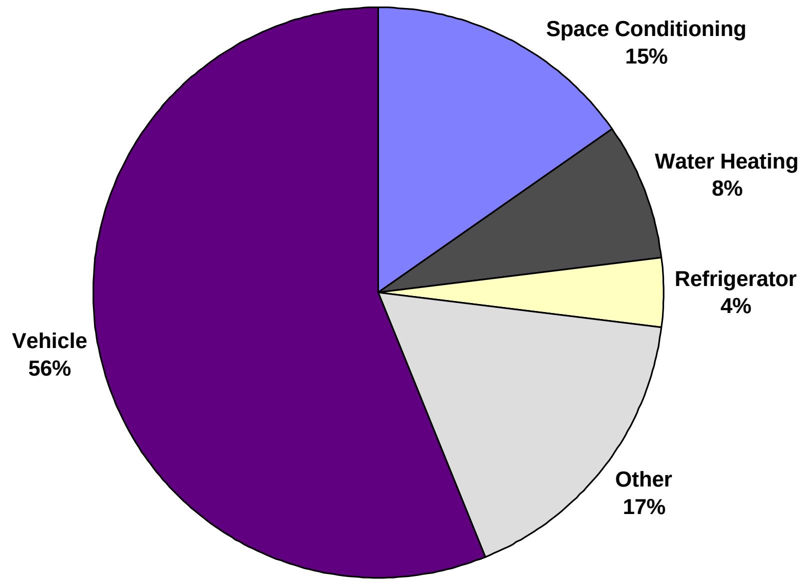
ADJUSTED FOR INFLATION, THE AVERAGE WASHINGTON HOUSEHOLD SPENT 8% MORE FOR HOME ENERGY IN 1997 THAN IN 1970. IMPROVEMENTS IN HOUSEHOLD ENERGY EFFICIENCY AND FUEL SWITCHING TO LESS EXPENSIVE ENERGY SOURCES HAVE OFFSET HIGHER ELECTRICITY PRICES.

In 1997, the average Washington household spent the inflation-adjusted sum of $944 for electricity, natural gas, and petroleum delivered to the home, roughly $70 more than in 1970. This outward similarity masks significant changes in the composition of household energy expenditures over the last 25 years. Increased emphasis on energy conservation and fuel switching from heating oil to wood helped to mitigate the impact of the oil shocks of the 1970s on the home energy bill of Washington households. However, there is no immediate substitute for electricity, so when electricity prices increased by 62% between 1980 and 1983, due largely to the inclusion in rates of the WPPSS nuclear bonds, the average household electricity bill increased by a like amount.

Over time, energy efficiency and fuel switching have helped reduce reliance on relatively expensive electricity. The electricity bill for the average Washington household dropped by 17% between 1985 and 1997; usage per household fell 7%. Many new homes were built with natural gas heat and numerous existing households saved by switching to natural gas as well. Switching to a cheaper fuel could mean significant savings; the average natural gas bill fell by 10% between 1985 and 1997, despite a 45% increase in per household consumption.

11. Residential Sector Trends — Household Energy Bill with Transportation

Household Energy Bill by End Use 1997 ($2,200)

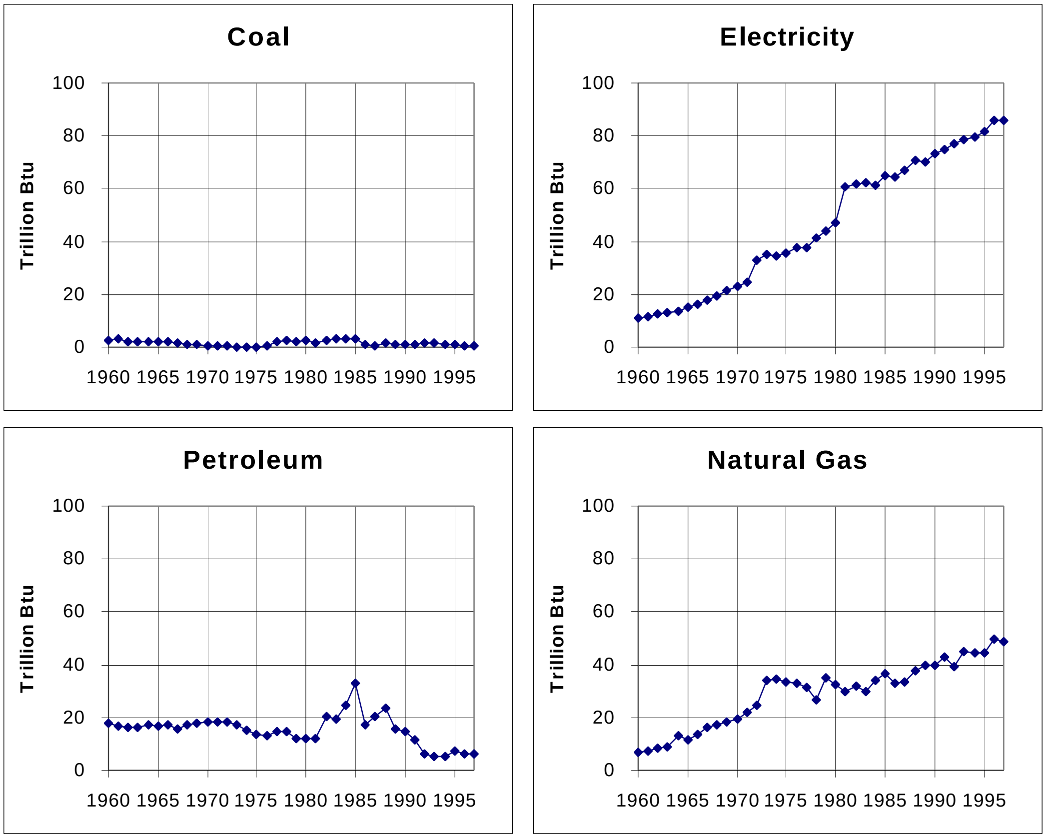


BY INCLUDING ENERGY USED FOR PERSONAL TRANSPORTATION, THE ANNUAL ENERGY BILL FOR THE AVERAGE WASHINGTON HOME MORE THAN DOUBLES[1].

Most views depicting residential energy data do not include the major components of consumption and expenditure at most homes – household vehicles. The average household in Washington spent 56% of its energy budget fueling vehicles for transportation in 1997. This share has increased dramatically in the last two decades. While homes are becoming more energy efficient, they are increasingly located at longer distances from where people work, shop, and recreate.

After personal transportation, major categories of household energy expenditures include space conditioning (heating, cooling, and ventilation), water heating, refrigerators, and other uses such as lighting, household appliances, and electronic equipment.

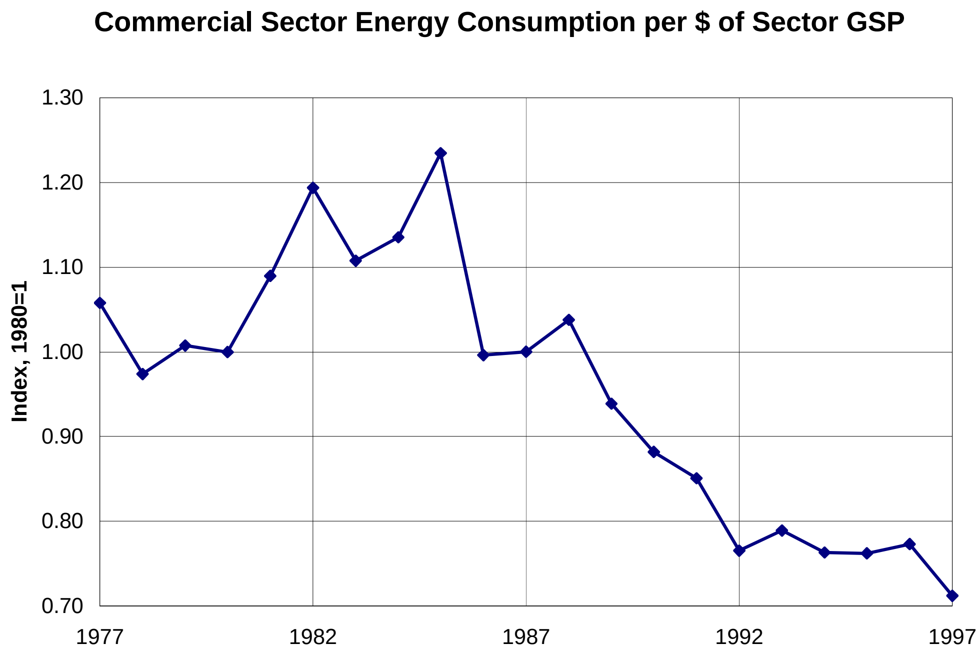
12. Commercial Sector Trends — End-Use Energy Consumption by Fuel



ELECTRICITY ACCOUNTS FOR OVER 60% OF END-USE ENERGY CONSUMPTION IN THE COMMERCIAL SECTOR. NATURAL GAS MAKES UP THE BULK OF THE REST. BOTH GAS AND ELECTRICITY CONSUMPTION CONTINUE TO GROW AT 2% PER YEAR.

Electricity and natural gas are the dominant fuels in Washington's commercial sector. With escalating use of electricity-consuming equipment such as computers, printers, and photocopiers, the commercial sector has become increasingly reliant on electricity during the last two decades. Commercial sector electricity consumption has nearly quadrupled since 1970. Natural gas lost market share in the late 1970s and early 1980s, but has recovered rapidly since 1985. In contrast, petroleum consumption is less than half of early 1970s levels, declining from 30% of commercial energy consumption in 1970 to around 5% in 1995.

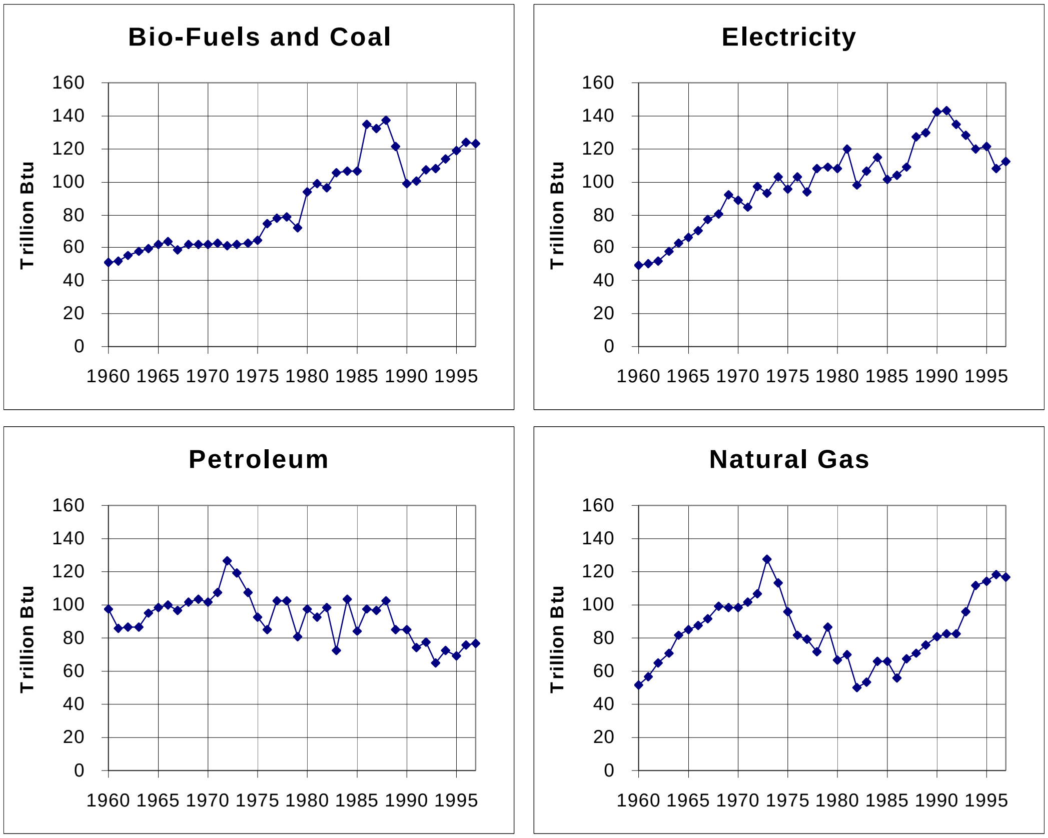
13. Commercial Sector Trends — Commercial Sector Energy Intensity



COMMERCIAL SECTOR ENERGY CONSUMPTION HAS DECLINED RAPIDLY RELATIVE TO ECONOMIC OUTPUT SINCE THE MID-1980S.

Washington's commercial sector has become much less energy intensive over the last 15 years. Commercial sector energy consumption increased more than 50% between 1977 and 1985, but has since grown only slightly. Meanwhile, the value of all goods and services produced by the commercial sector has more than doubled in real terms since 1977 and continues to grow at 4% per year. Increased productivity and improvements in the efficiency of buildings, lighting, and equipment have played major roles in declining commercial sector energy intensity.

14. Industrial Sector Trends — End-Use Energy Consumption by Fuel

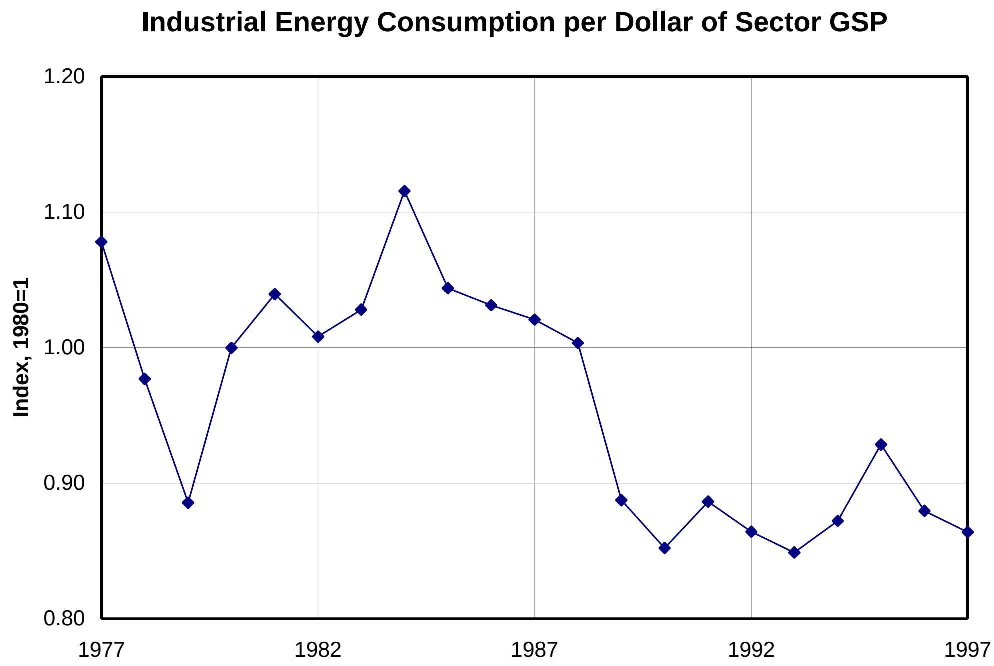


INDUSTRIAL ENERGY CONSUMPTION IN WASHINGTON IS SPLIT MORE EVENLY AMONG BIOFUELS[1], ELECTRICITY, NATURAL GAS, AND PETROLEUM THAN OTHER SECTORS. AS IN OTHER SECTORS, GROWTH IN NATURAL GAS CONSUMPTION HAS ACCELERATED DURING THE 1990S.

Unlike the residential and commercial sectors, which rely primarily on electricity and natural gas, or the transportation sector which consumes almost exclusively petroleum fuels, energy consumption in Washington's industrial sector is quite diversified. Biofuels, electricity, and natural gas each accounted for between 26 and 28% of industrial sector energy consumption during 1997, with petroleum contributing about 18%. With the exception of natural gas, the relative market share of each of the fuels has not changed dramatically since 1970. Natural gas consumption declined precipitously between 1973 and 1983, but growth has accelerated in recent years. Industrial natural gas consumption grew 23% from 1985 to 1990, and 44% from 1990 to 1997.

The industrial sector is the most affected by changes in methodology from the previous edition of Energy Indicators which removed large additional amounts of non-energy petroleum use from our analysis (see Sources and Methodology).

15. Industrial Sector Trends — Industrial Sector Energy Intensity

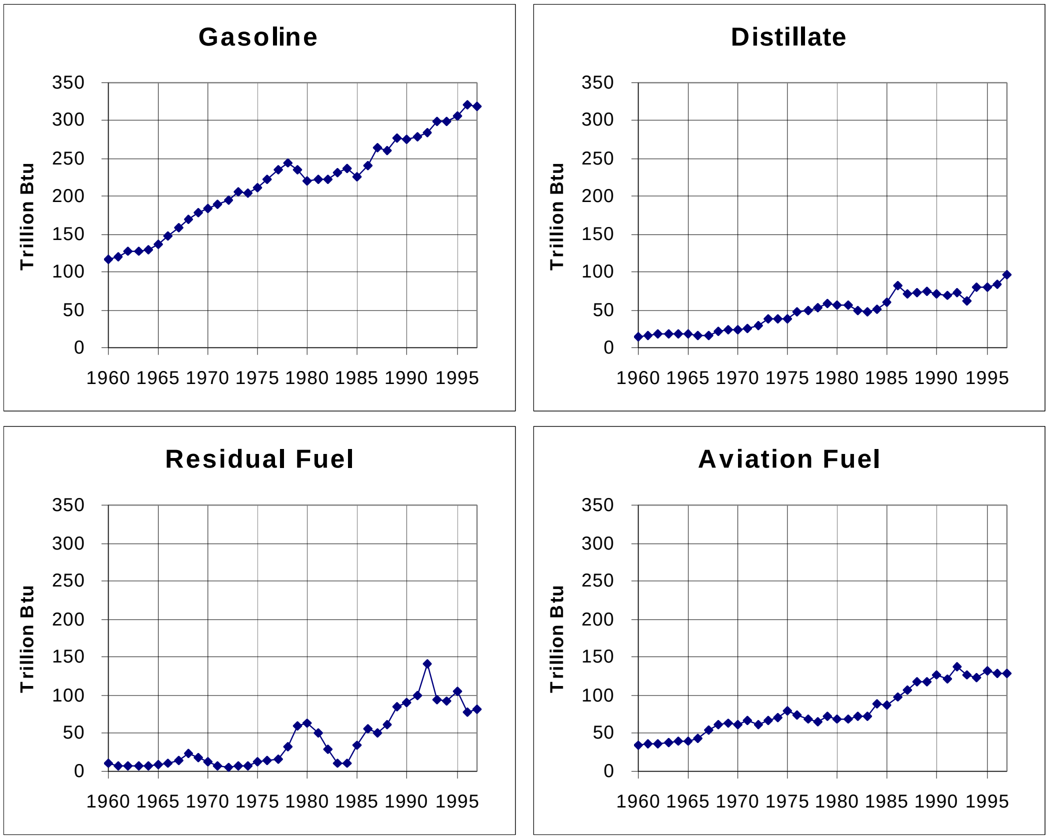


Energy Intensity in Washington's Industrial sector has declined over the past ten years, but remains more volatile than other sectors.

Washington's industrial sector is less energy-intensive than it was two decades ago, but that is not a consistent trend over that period. Both energy consumption and industrial production are extremely volatile, making it difficult to discern underlying trends. Energy consumption in the industrial sector can vary by as much as 10% from one year to the next. Petroleum energy use in particular commonly lurches up one year and down the next. Industrial production contracted 15% between 1979 and 1985, then grew by 35% between 1985 and 1990, then averaged $31 billion per year in constant, 1996 dollars through 1995 before spiking to above $35 billion dollars in 1997.

It should be noted that we estimate that electricity consumption in the industrial sector is underreported by between 7 and 10% for 1996 and 1997, because the surveys do not report purchases of non-federal power by the direct service industries. With electricity making up slightly more than one fourth of total industrial energy, such a shift would raise the index shown here only slightly, from 0.88 to 0.90 in 1996 and from 0.86 to 0.89 in 1997.

16. Transportation Sector Trends — End-Use Energy Consumption by Fuel

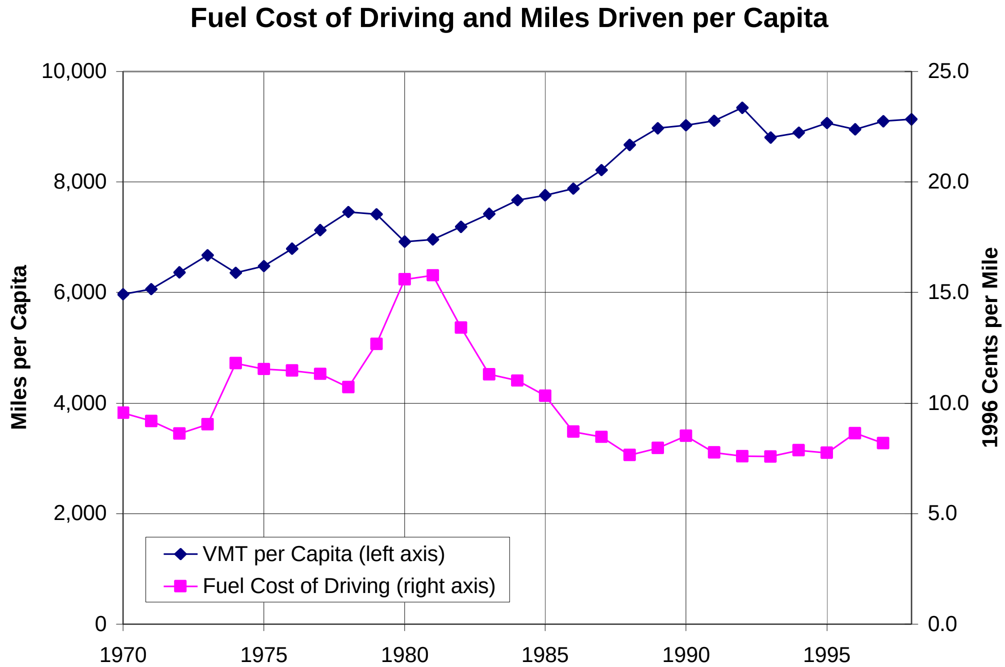


GASOLINE ACCOUNTS FOR HALF OF TRANSPORTATION SECTOR ENERGY USE IN WASHINGTON. WHILE WASHINGTONIANS DRIVE MORE THAN OTHER AMERICANS, WASHINGTON'S STATUS AS A MAJOR SEAPORT AND AVIATION HUB MEANS HIGHER CONSUMPTION OF AVIATION AND MARINE FUELS AS WELL.[1]

Motor gasoline is the dominant transportation fuel, accounting for approximately half of Washington's transportation energy consumption. Except for the period between 1978 and 1986, demand for travel has outstripped gains in vehicle fuel efficiency, leading to steady growth in gasoline consumption. Consumption of distillate fuels in trucks (as diesel fuel), ships, and railroads has also grown. Residual fuel, used for vessel bunkering, is subject to price-induced volatility because it can be stored for long periods of time without degrading.

Jet fuel consumption most closely resembles the overall transportation trends. Declining jet fuel prices have contributed to a significant increase in air travel, overwhelming efficiency improvements in the stock of private, commercial, and military planes. Jet fuel use more than doubled between 1970 and 1997, growing at an average annual rate of 2.9%.

17. Transportation Sector Trends — Fuel Cost of Driving and Miles Driven

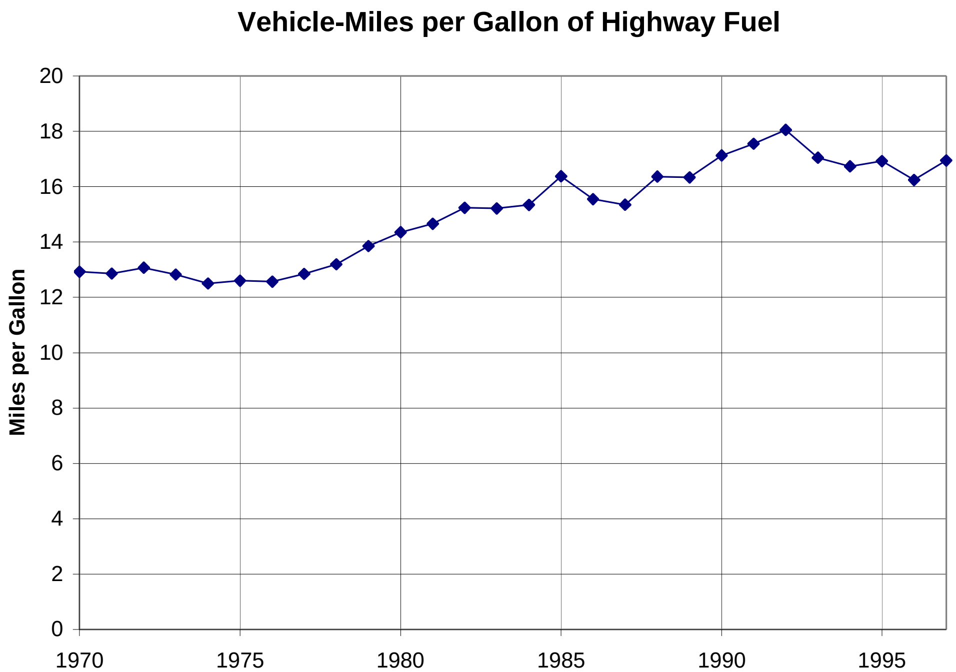


WASHINGTONIANS DROVE 53% MORE MILES PER CAPITA IN 1998 THAN THEY DID IN 1970. A BIG REASON IS THE FUEL COST OF DRIVING, WHICH REMAINED NEAR HISTORIC LOWS.

This indicator juxtaposes the fuel cost of driving with miles per driven per capita in Washington. Not surprisingly, these series exhibit a strong inverse relationship. The fuel cost of driving, calculated as real dollar highway energy expenditures divided by vehicle-miles traveled (VMT), spiked upward in 1974 and 1979-1980 as a result of the oil shocks. VMT per capita dropped slightly in response to higher prices, as unnecessary driving was temporarily curtailed. However, long-term factors such as land-use patterns, commuting habits, and the long lifetimes of vehicles mean that large swings in fuel prices lead to only small changes in miles driven.

Increasing sales of more fuel-efficient vehicles in the early 1980s combined with declines in the price of highway fuels to cause a rapid drop in the fuel cost of driving, from a high of 15.8¢ per mile in 1981 to 8.7¢ in 1986 (in 1996 dollars). Gains in fuel efficiency since the early 1970s made this the lowest value in history. However, real gasoline prices have changed little since 1986, and increases in vehicle fuel efficiency have slowed dramatically as well. Meanwhile, vehicle travel increased steadily before an unexplained drop in 1993.

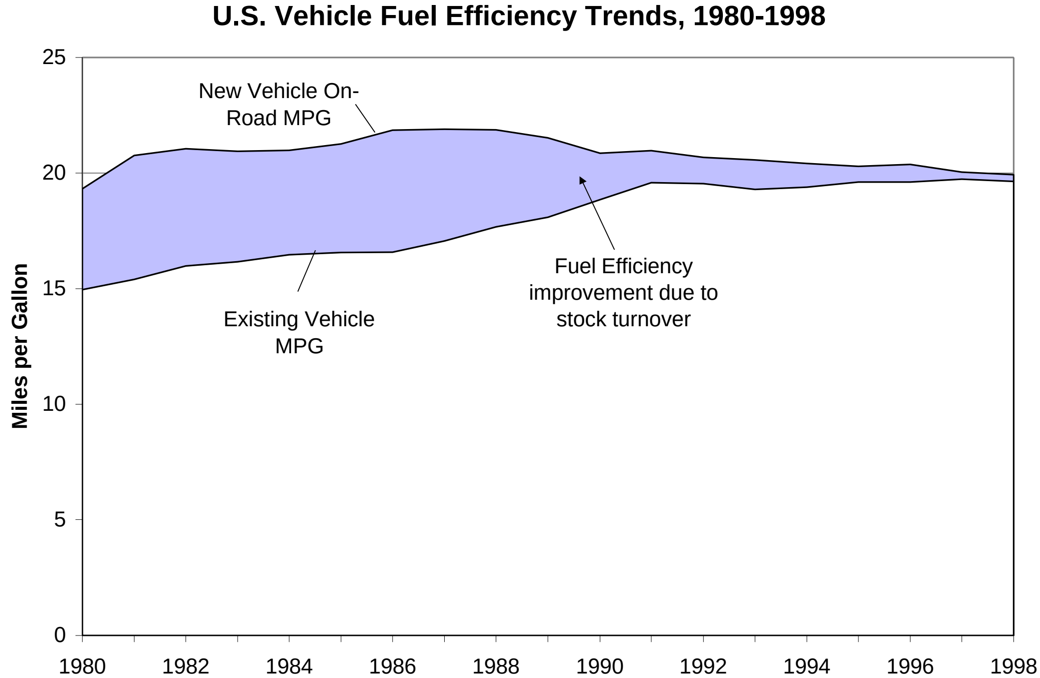
18. Transportation Sector Trends — Transportation Sector Energy Intensity



SPURRED BY HIGH GASOLINE PRICES, VEHICLE FUEL EFFICIENCY INCREASED BY MORE THAN A THIRD BETWEEN 1975 AND 1985[1]. INCREASING POPULARITY OF VANS, TRUCKS, AND SPORT UTILITY VEHICLES IN THE 1990S MAY HAVE PUT AN END TO THAT TREND.

Like other sectors, Washington's transportation sector has become more energy efficient over the years. The average efficiency of Washington's vehicle fleet grew from 12.5 MPG in 1975 to 14.2 MPG in 1980 and 17.0 MPG in 1990. However, fifteen years of improvements in vehicle fuel efficiency appear to have come to an end in the 1990s. In fact, fuel efficiency for new vehicles has declined since the mid-1980s, when federal fuel standards were last tightened. The primary reason is the increasing popularity of minivans, pickups, and sport-utility vehicles.

19. Transportation Sector Trends — U.S. Vehicle Fuel Efficiency

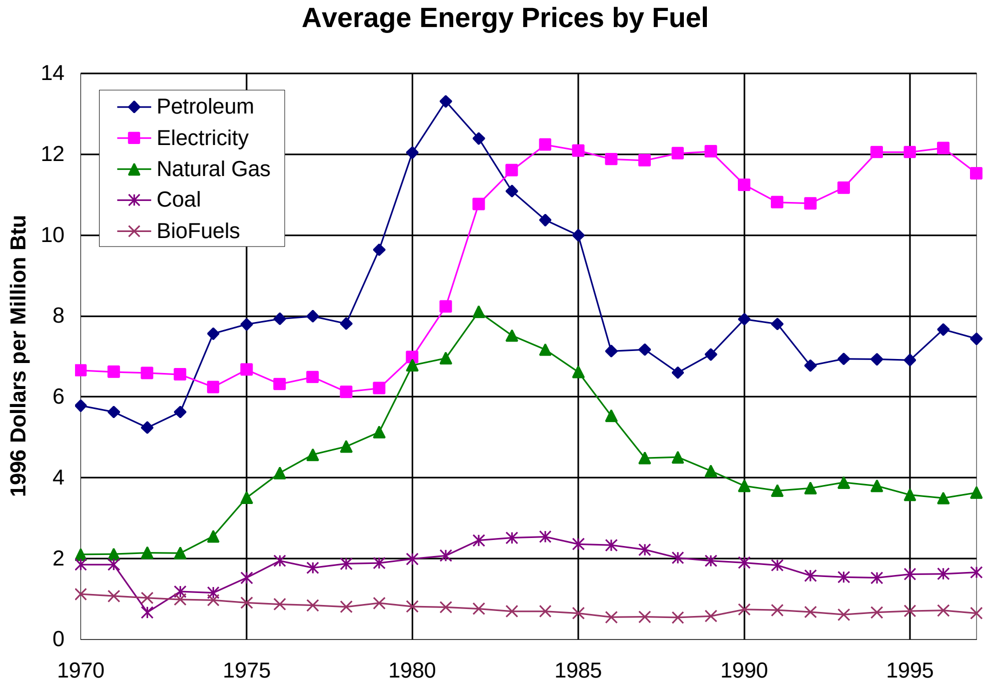


THE FUEL EFFICIENCY ADVANTAGE OF NEW VEHICLES RELATIVE TO THE EXISTING VEHICLE FLEET IS DISAPPEARING. INCREASING POPULARITY OF LARGER VEHICLES, COMBINED WITH THE AGING OF 1980S-ERA SUBCOMPACTS, MAY MEAN AN END TO YEARS OF FUEL EFFICIENCY IMPROVEMENTS.

The difference between the fuel efficiency of new vehicles and that of the nation's existing vehicle fleet continues to shrink and may even have disappeared. New vehicle fuel efficiency has been declining since the mid-1980s, when Congress last increased Corporate Average Fuel Economy (CAFE) standards. CAFE standards require companies to maintain the average fuel efficiency of new vehicles at 27.5 MPG for cars and 20.5 MPG for light trucks (which includes minivans, pickups, and sport-utility vehicles).[1] However, CAFE has no mandates about how many vehicles may be sold in each category, and the increasing popularity of light trucks has caused the fuel efficiency of the average new vehicle to drop by more than two miles per gallon (MPG) since 1988.

Moreover, the vehicles being replaced are no longer 1970s-era gas-guzzlers, but are frequently compact, fuel-efficient, cars of the 1980s. The result is that, unlike in other sectors where newer equipment tends to be more energy efficient, vehicle stock turnover may be leading to a less efficient national fleet. With the average lifetime of light-duty vehicles being more than seven years and little prospect of declining demand for travel, Washington petroleum consumption looks set to increase for some years.

20. Energy Price Trends — Average Energy Prices by Fuel

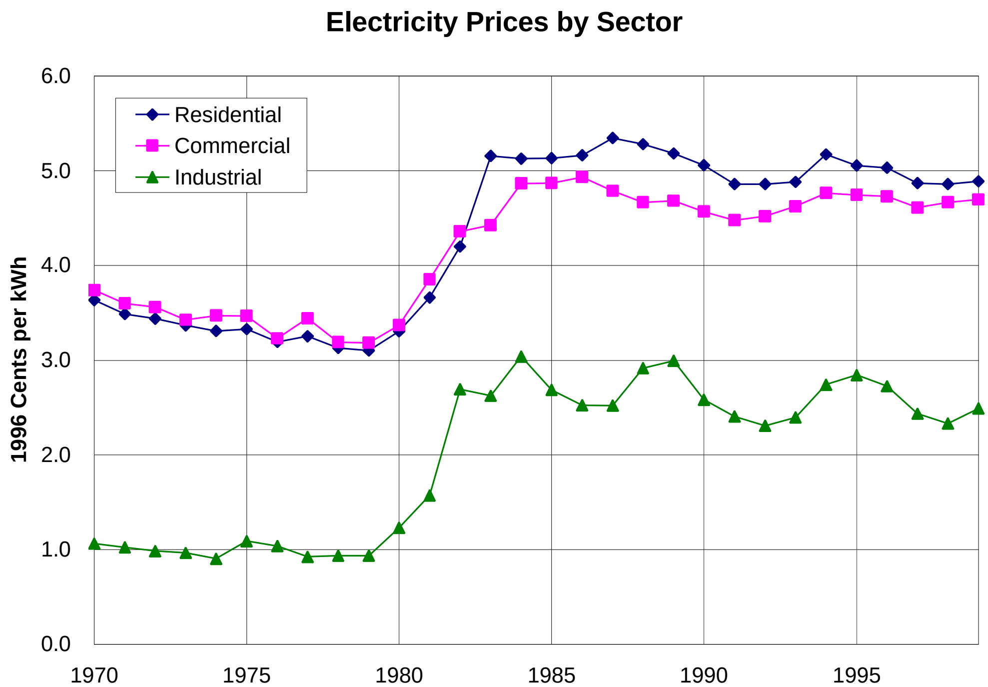


EVEN THOUGH ELECTRICITY PRICES IN WASHINGTON TEND TO BE LOWER THAN IN OTHER PARTS OF THE COUNTRY, ELECTRICITY IS STILL THE MOST EXPENSIVE ENERGY SOURCE. REAL FOSSIL FUEL PRICES HAVE DECLINED SIGNIFICANTLY SINCE THE EARLY 1980'S, BUT AVERAGE ELECTRICITY PRICES HAVE REMAINED CONSTANT.

While the effect of the oil shocks of 1973 and 1978 on Washington energy prices was dramatic, it was relatively short-lived. Petroleum prices increased by 50% in 1974, increased by another 63% between 1978 and 1981, and then quickly settled back to pre-1973 levels. Real natural gas prices have followed a similar trend, rising steeply during the 1970s, falling during the 1980s, and staying relatively stable in the 1990s. The average price of electricity, which had been low and stable for years, increased by 95% between 1979 and 1984 as the costs of new, large power plants, some of which were never completed, were incorporated into electric utility rates. In contrast to oil prices, real electricity prices have not declined from the level they reached during the early 1980s.

The price increases for all fuels caused real Washington energy expenditures to climb by 56% between 1978 and 1982. Expenditures were 25% lower by 1986 as the price of fossil fuels plummeted, but have since climbed back near the levels of the early 1980s, as energy consumption has increased.

21. Energy Price Trends — Average Electricity Prices by Sector

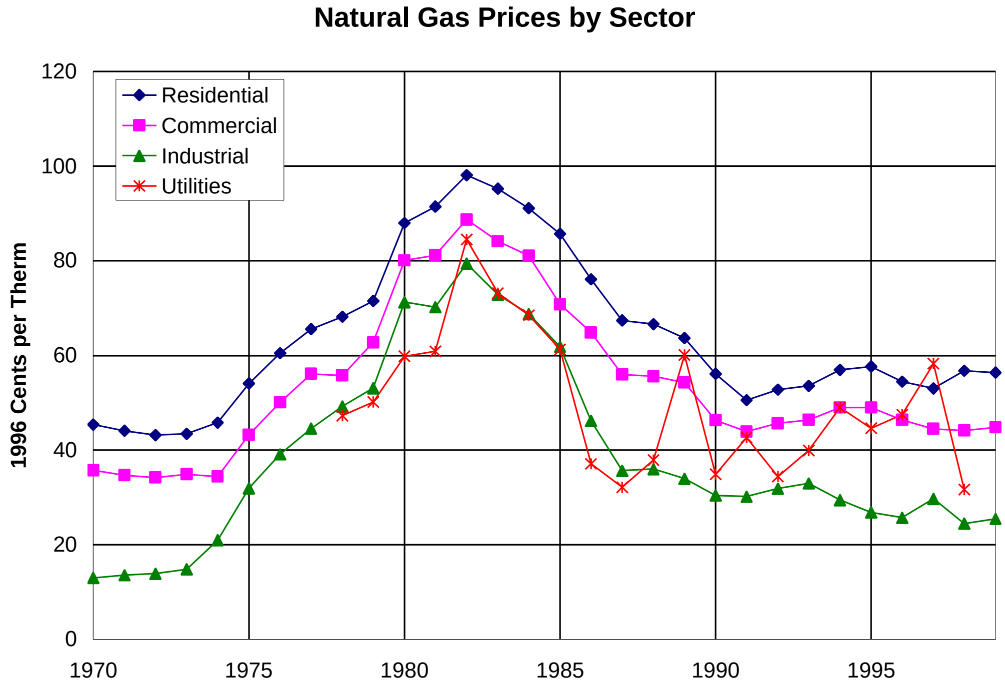


REAL ELECTRICITY PRICES INCREASED DRAMATICALLY BETWEEN 1979 AND 1984 AND STAYED CONSTANT THROUGH 1999. THE MAGNITUDE OF THE INCREASE, PRIMARILY DUE TO NUCLEAR DEBT, WAS SIMILAR FOR ALL SECTORS BUT THE RELATIVE INCREASE WAS MUCH HIGHER FOR THE INDUSTRIAL SECTOR.

The most notable phases in electricity prices are the long, slow decline of prices in the 1970s, the rapid increase between 1979 and 1984, and the period since 1984 when no trend is evident. Price trends for the residential and commercial sectors are nearly identical. Industrial sector prices have been more volatile than residential and commercial prices, increasing over 200% between 1979 and 1984, versus 50-60% for the residential and commercial sectors. On a per unit basis, however, the increases were similar for all sectors: 1.9¢ per kWh for the residential, 1.6¢ per kWh for the commercial, and 2.0¢ per kWh for the industrial sector.

Industrial prices have fluctuated as much as half a cent per kWh from year to year during the 1980s and 1990s. This may have as much to do with world aluminum prices as it does with Northwest electricity prices. Aluminum smelters, which account for nearly half of industrial sector energy consumption in Washington, paid electricity prices contractually linked to aluminum prices for much of the time period depicted.

22. Energy Price Trends — Average Natural Gas Prices by Sector

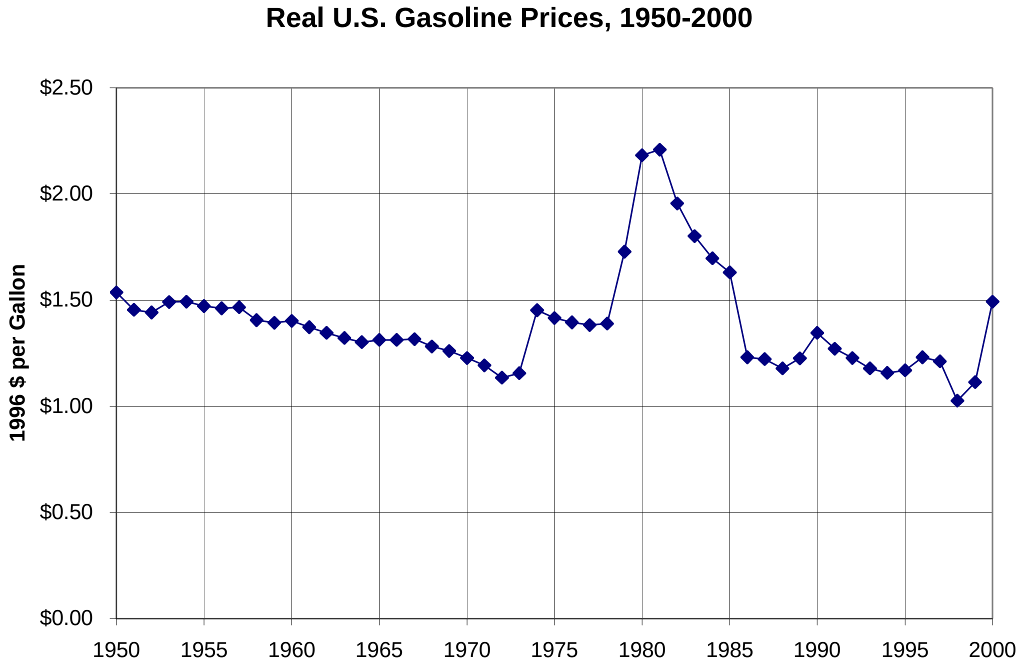


NATURAL GAS PRICES INCREASED RAPIDLY FOR ALL SECTORS BETWEEN 1974 AND 1982 AND DECLINED JUST AS RAPIDLY FROM 1982 TO 1991. INDUSTRIAL SECTOR GAS PRICES HAVE DECLINED SINCE 1993, WHILE RESIDENTIAL AND COMMERCIAL RATES HAVE SEEN MODEST INCREASES.

Price trends for natural gas have been much more uniform across sectors than for electricity. For all sectors, real prices were stable in the early 1970s, increased rapidly between 1974 and 1982, and declined just as rapidly between 1982 and 1991. As with electricity, the price increases during the 1970s were of similar magnitude in all sectors on a per unit basis, but were much larger in percentage terms for the industrial sector. Real natural gas prices increased by approximately 50¢ per therm for all sectors between 1973 and 1982.

Price trends have diverged in the 1990s. Residential and commercial customers experienced price increases of 11.5% and 2%, respectively, between 1991 and 1999. Average industrial sector natural gas prices declined by 15.5% over the same period. Many large industrial customers have begun to make bulk purchases of commodity gas from suppliers other than their local utilities. Natural gas in the utility sector has historically been used to fire relatively small power plants used for “peaking“, which at least partially explains the volatility experienced in that sector. With a number of gas-fired plants in the planning stages, utility sector consumption of natural gas will soon become much more significant.

23. Energy Price Trends — U.S. Gasoline Prices since 1950



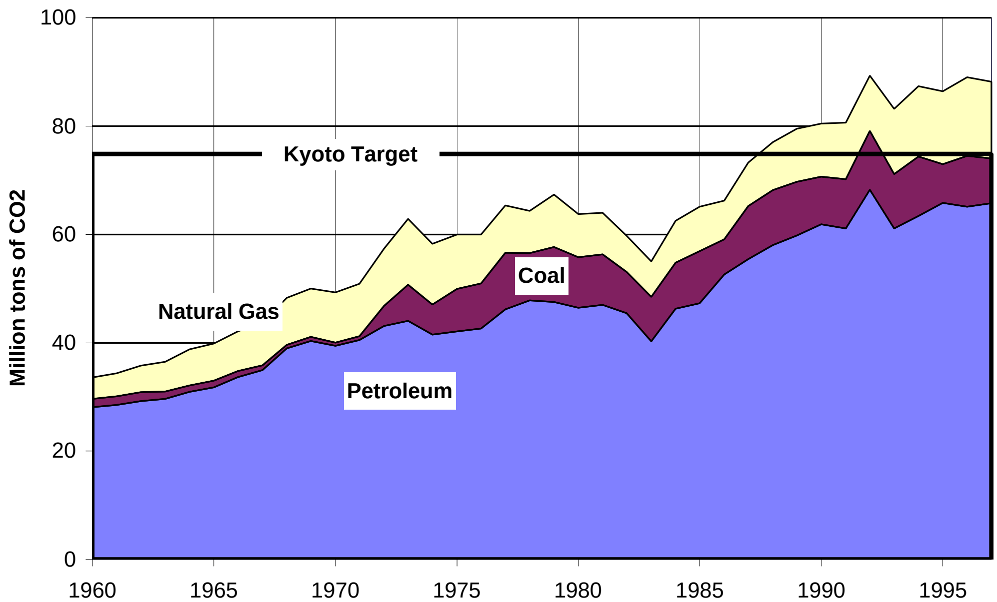
ADJUSTED FOR INFLATION, GASOLINE COST LESS IN 1998 AND 1999 THAN AT ANY TIME IN HISTORY. PRICES ROSE SUBSTANTIALLY IN 2000[1], TO LEVELS NOT SEEN SINCE THE HEYDAY OF OPEC IN THE MID-1980S.

After falling to their lowest levels in history in February, 1999, U.S. gasoline prices rose 50¢ per gallon over the next 12 months. The increase was kicked off by a two million barrel per day cut by the Organization of Petroleum Exporting Countries (OPEC) in March 1999, but years of declining fuel efficiencies and increasing consumption left the country more vulnerable than it had been to supply shocks.

Before 1999, the dominant trend in gasoline prices was slow and steady decline, with the exception of the 1973-1985 period of OPEC unity. The discovery of new fields, better technology, and improved infrastructure have reduced the cost of extracting, transporting, and refining crude oil. Prices plunged when the OPEC agreements fell apart in 1985, and stayed relatively low until the events of 1999. Adjusted for inflation to 1996 dollars, a gallon of gasoline cost $2.18 in 1980, $1.23 in 1970, and $1.54 in 1950, as compared to $1.49 through the first nine months of 2000.

24. Environmental Trends — Energy-Related Greenhouse Gas Emissions

Carbon Dioxide Emissions from Energy Use by Soure



WASHINGTON'S INCREASING RELIANCE ON FOSSIL FUELS HAS LED TO STEADY GROWTH IN EMISSIONS OF CARBON DIOXIDE, THE PRINCIPAL GREENHOUSE GAS. PETROLEUM USE, PRIMARILY FOR TRANSPORTATION, ACCOUNTS FOR 75% OF CO_2 EMISSIONS IN WASHINGTON.

Washington's continued dependence on fossil fuels for energy, particularly petroleum, has led to rapid growth in emissions of carbon dioxide (CO_2), the principal "greenhouse gas" contributing to global climate change.[1] After dipping in the early 1980s, growth in carbon dioxide emissions accelerated after 1983 as the economy recovered from recession and oil prices plummeted. Washington's CO_2 emissions from energy use grew by 2.6% per year between 1985 and 1997.

Consumption of petroleum products, the vast majority for transportation, accounts for three-quarters of Washington's CO_2 emissions. Emissions from coal are almost entirely from one source, the Centralia Steam Plant which burns coal to produce electricity. Natural gas contains less carbon per unit of energy than other fossil fuels, but still accounts for a larger share of Washington's CO_2 emissions than coal.

Also depicted is the emission target agreed to during the Kyoto negotiations in 1997, which is 7% below 1990 levels. Meeting this target would require a 15% reduction from Washington's 1997 emissions level.

Sources and Data Notes

1 Washington's Energy Use — End-Use Energy Consumption By Sector

Source: Energy Information Administration's State Energy Data System

2 Washington's Energy Use — Primary Energy Consumption by Source

Source: Energy Information Administration's State Energy Data System

Note 1: EIA uses each state's mix of electric generation to map electricity consumption to production by primary fuels. This overstates the contribution of hydroelectricity, as Washington is part of an interconnected regional electric grid and relies on generation sources in other states that are less hydroelectric-intensive. (See Indicator #3).

Note 2: The difference between primary and end-use energy consumption is the treatment of electricity. Electricity must be generated using energy sources such as coal, natural gas, or falling water. These inputs to the power plant are counted as primary energy; the output of the power plant that is sold to homes and businesses is end-use electricity. Since two-thirds of the energy inputs to thermal power plants are typically lost as waste heat, primary energy is larger than end-use.

3 Washington's Energy Use — Electricity Generation

Source: Energy Information Administration, Electric Generator Database

Note 1: The U.S. portion of the Northwest Power Pool includes Washington, Oregon, Idaho, Montana, and parts of Wyoming and Nevada.

Note 2: The Western Interconnection refers to the geographical area encompassed by the interconnected western transmission grid. It includes all or most of Washington, Oregon, Idaho, Montana, Wyoming, Utah, Nevada, Colorado, New Mexico, Arizona, California, the Canadian provinces of British Columbia and Alberta, and the Mexican state of Baja California Norté. It also includes small portions of Texas, Nebraska, and South Dakota.

4 Washington's Energy Bill — End Use Energy Expenditures

Sources: Energy Information Administration's State Energy Data System; Council of Economic Advisors, The 2000 Annual Economic Report of the President

5 Washington's Energy Intensity — Energy Consumption per Dollar of Gross State Product

Sources: Energy Information Administration's State Energy Data System; U.S. Department of Commerce, Bureau of Economic Analysis

6 Washington's Energy Intensity — Energy Consumption per Capita

Sources: Energy Information Administration's State Energy Data System; U.S. Department of Commerce, Bureau of the Census

7 Washington's Energy Intensity — Energy Expenditures per Dollar of Washington GSP

Sources: Energy Information Administration's State Energy Data System; Bureau of Economic Analysis

Note 1: Energy expenditures include expenditures by households as well for personal transportation.

8 Residential Sector Trends — End-Use Energy Consumption by Fuel

Source: Energy Information Administration's State Energy Data System

Note 1: The primary petroleum products consumed in households are heating oil (No. 2 distillate oil) and propane. Both are consumed mainly for space heating, though propane can also be used for cooking and water heating.

9 Residential Sector Trends — Household Energy Intensity

Sources: Energy Information Administration's State Energy Data System; U.S. Department of Commerce, Bureau of the Census

10 Residential Sector Trends — Household Energy Bill

Sources: Energy Information Administration's State Energy Data System; U.S. Department of Commerce, Bureau of the Census

11 Residential Sector Trends — Household Energy Bill with Transportation

Source: Energy Information Administration, Residential Energy Consumption Survey

Note 1: These detailed figures about household energy expenditures were obtained from a different source than data used elsewhere in this report. As a result, this estimate of the average household energy bill differs slightly from that in the previous indicator.

12 Commercial Sector Trends — End-Use Energy Consumption by Fuel

Source: Energy Information Administration's State Energy Data System

13 Commercial Sector Trends — Sector Energy Intensity

Sources: Energy Information Administration's State Energy Data System; U.S. Department of Commerce, Bureau of Economic Analysis

14 Industrial Sector Trends — Energy Consumption by Fuel

Source: Energy Information Administration's State Energy Data System

Note 1: Bio-fuels consumed in the industrial sector comprise mainly wood and wood waste products such as black liquor or hog fuel. These fuels are primarily burned in industrial boilers to make steam, which can be used to fire industrial processes or to generate electricity for on-site use. Industrial coal consumption has declined from a high of 14 trillion Btus in 1976 to 3 trillion Btus in 1997.

15 Industrial Sector Trends — Industrial Sector Energy Intensity

Sources: Energy Information Administration's State Energy Data System; U.S. Department of Commerce, Bureau of Economic Analysis

16 Transportation Sector Trends — End-Use Energy Consumption by Fuel

Source: Energy Information Administration's State Energy Data System

Note 1: Motor gasoline figures include some consumption for off-road uses such as recreational vehicles and agricultural uses. No. 2 distillate, also known as diesel fuel, is used by large trucks, ships, and railroads. The only transportation use for residual fuel is by very large ships. Aviation fuel includes kerosene-based jet fuel used by major airlines, aviation gasoline consumed by smaller airplanes, and military jet fuel.

17 Transportation Sector Trends — Fuel Cost of Driving and Miles Driven per Capita

Sources: Energy Information Administration's State Energy Data System; U.S. Department of Commerce, Bureau of the Census; U.S. Department of Transportation, Federal Highway Administration

18 Transportation Sector Trends — Transportation Sector Energy Intensity

Sources: Energy Information Administration's State Energy Data System; U.S. Department of Transportation, Federal Highway Administration

Note 1: Data includes fuel consumption by heavy-duty trucks in addition to personal vehicles.

19 Transportation Sector Trends — US Vehicle Fuel Efficiency Trends

Sources: Energy Information Administration's State Energy Data System; Oak Ridge National Laboratories

Note 1: Official, EPA-rated fuel efficiency. The Energy Information Administration estimates actual, on-road performance to be 13.9% worse than the EPA rating for cars and 18.6% worse for light trucks (EIA, *National Energy Modeling System*, Fuel Economy Degradation Factor). This means that the average fuel economy of vehicles sold in 1998 is 19.9 MPG, as opposed to 23.9 estimated by EPA. This is very close to the average, on-road fuel efficiency of the nation's existing stock of light-duty vehicles, which is estimated to be 19.6 MPG (Oak Ridge National Laboratory, *Transportation Energy Data Book*).

20 Energy Price Trends - Average Energy Prices by Fuel

Sources: Energy Information Administration's State Energy Data System; U.S. Department of Commerce, Bureau of Economic Analysis

21 Energy Price Trends - Average Electricity Prices by Sector

Sources: Energy Information Administration's State Energy Data System; U.S. Department of Commerce, Bureau of Economic Analysis

22 Energy Price Trends - Average Natural Gas Prices by Sector

Sources: Energy Information Administration's State Energy Data System; U.S. Department of Commerce, Bureau of Economic Analysis

23 Energy Price Trends - US Gasoline Prices since 1950

Source: Energy Information Administration's Annual Energy Review;

Note 1: 2000 value is an estimate based on data for January-September.

24 Environmental Trends - Energy-Related Greenhouse Gas Emissions

Sources: Energy Information Administration's State Energy Data System, Kyoto Protocol

Note 1: These estimates include emissions of greenhouse gases due to the use of petroleum coke as a reactant in industry, which is arguably not "energy-related". However, there are some additional energy-related emissions of greenhouse gases not due to the combustion of fuels that are not included in this indicator. These include releases of methane (CH_4) from coal mining and natural gas pipeline leakage and nitrous oxide (N_2O) released from catalytic converters used on light duty automobiles. These emissions accounted for about 6% of Washington's total, energy-related greenhouse gas emissions in 1995.

Methodology

Introduction

Most publicly available comprehensive energy data at the state level originate with surveys and estimates developed by the Energy Information Administration (EIA), an independent branch of the federal Department of Energy. We rely heavily on the EIA's State Energy Data System (SEDS) to produce Energy Indicators and other products. However we modify data from the EIA, based on years of experience with their components and their fit with the needs of the Energy Indicators.

Modifications to Source Data

Readers of the previous edition may notice a significant difference in several indicators. Most of the change is due to a revision in our methodology involving the treatment of petroleum products used in industrial processes, but not as fuels. This resulted in significant changes in the industrial sector, especially in the most recent 15 years. We also differ with EIA's approach to calculating the energy value for hydroelectricity in primary views. Additionally, since the publication of the previous Indicators, the EIA has provided a complete series on biofuels for all sectors. Originally, these data were provided only when used as inputs to generate electricity. A partial record was later established, with the series beginning in 1990, requiring us to generate estimates for missing years. Now a complete series is available from EIA, and it differs significantly from our earlier estimates.

Excluded Petroleum Products

In the previous edition, we excluded asphalt, road oil, and lubricants from the transportation and industrial sectors. These are easily removed series that are clearly not used as energy sources. In this edition we have removed additional non-energy petroleum products.

Among the products excluded from our energy analysis is industrial petroleum coke, used in various forms as a source of pure carbon. We have also excluded other uses such as petroleum used as feedstock for paints and solvents, or to make waxes to coat packaging. The focus of this analysis is energy consumption in Washington, rather than the supply of and demand for petroleum products or other fossil fuels. Excluding these non-energy uses provides the most accurate picture of the consumption of energy in the state.

The EIA series for industrial coke comprises coke used in oil refining and primary aluminum smelting. Neither of these processes uses coke for its energy content, but rather for its catalytic and conductive properties. These two types of coke are allocated to states, not according to measured use at the state level, but instead based on their share of the United States' annual capacity in the respective industries multiplied against US industrial coke use. The capacity of both these industries has grown considerably in Washington, and their share of the US total has also grown.

Indexed against 1970, the first year in which data pairs showing consumption and expenditure are available in SEDS, the Washington aluminum industry expanded by almost a third by 1997, and represented the largest primary smelting share of any state, at 29% of the nation's total.

While representing a much smaller share of the nation's petroleum refining industry, Washington's oil refineries have seen continued growth throughout the span of the data in these Indicators, while US capacity has changed little since the mid-80s.

The effect of these growing industries combined with the EIA inclusion of the (non-energy) petroleum coke they use as industrial energy consumption has resulted in distortion of the true patterns of industrial energy consumption, and thus an inflated view of energy use overall in Washington. That effect is magnified in the past two decades, when at

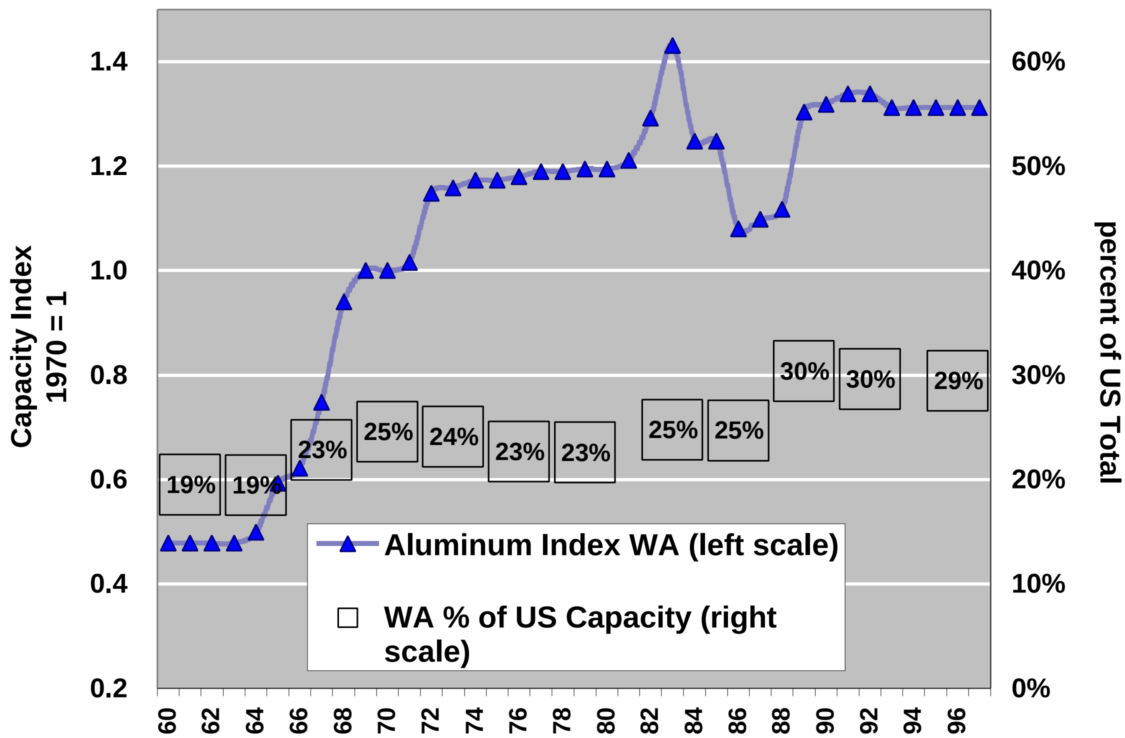


Figure 20 Washington Aluminum Ingot Capacity

Source: EIA SEDS

their peak, these non-fuel petroleum products accounted for more than 1/4th of the total Washington industrial energy use claimed by the EIA.

Non-utility Electricity Sales

An issue which does not represent a shift in methodology but which also hampers attempts to depict comprehensive energy use trends accurately is the changing nature of the electricity industry. Electricity is increasingly supplied to end-users by non-utility providers, out-of-state utility power marketers, or is generated on-site in many industrial facilities. Beginning in 1996, aluminum producers in Washington began to purchase power from such providers. These purchases escaped the utility focus of the EIA's collection efforts for the SEDS. Only for recent years not included in these Indicators are detailed totals of those sales becoming clearer. We anticipate a more accurate historical record of industrial electricity consumption to emerge in the next eighteen months. For this version of the Indicators, we estimate that electricity consumption in the industrial sector is underreported by between seven and 10% for 1996 and 1997.

However, it should be noted that the fuels used to power on-site industrial electric generation are reflected in that sector's totals, not as kilowatt-hours consumed but as fuel burned. So a small amount of the biomass, natural gas, and other fuels shown there can be assumed to be used to power on-site generation.

Hydroelectric Conversion

One last methodological note must be made to explain the differences one may notice here compared to other tallies of state energy use. In a steam powered generator, as much as two-thirds of the heat in the fuel burned to produce electricity is lost. Hydroelectric power generation does not experience thermal losses, but the EIA assigns losses to it equivalent to an average

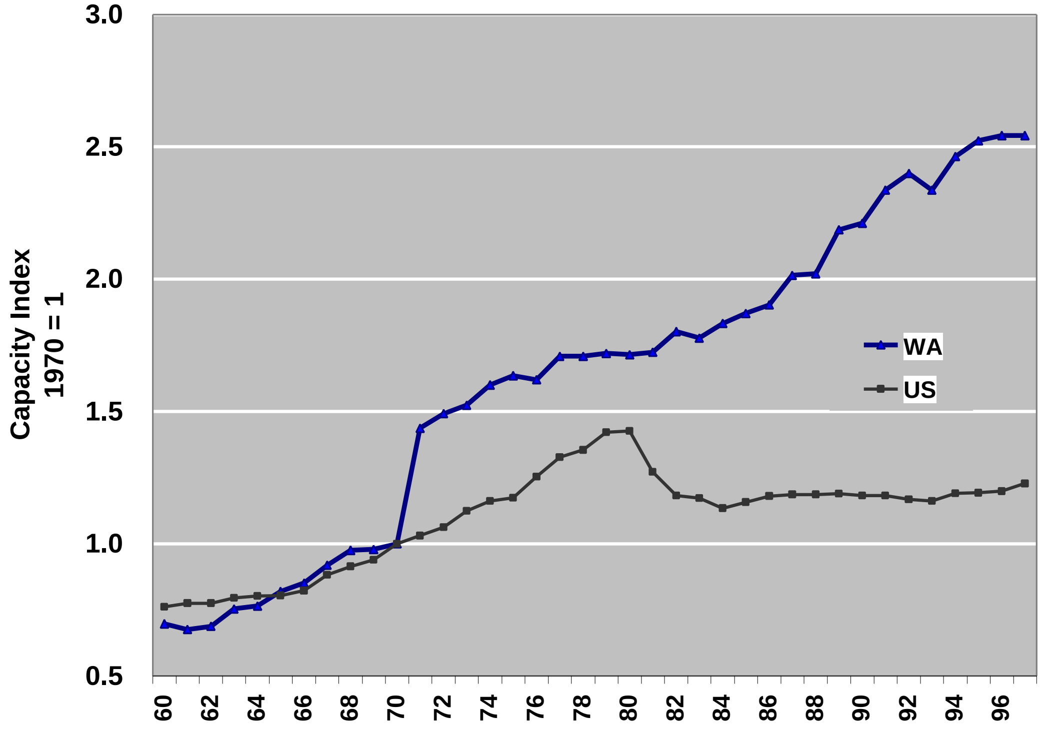


Figure 21 Washington's Operating Oil Refining Capacity

Source: EIA SEDS

loss rate for fossil fuel powered generation, in an effort to enable comparison of primary energy consumption between individual states. We remove those imputed losses from our primary totals. This difference does not affect depictions of sector end-use consumption of energy, as these do not show primary consumption.

Methodology Summary

In summary, large amounts of non-energy petroleum products used in aluminum smelting and oil refining, significant purchases of electricity in recent years other than from in-state utilities, and the large role hydroelectricity plays in the state's energy supply require modifications to standard views of energy consumption to portray accurately the trends depicted in these Indicators.

RCW 43.21F.010
Legislative finding and declaration.

The legislature finds and declares that it is the continuing purpose of state government, consistent with other essential considerations of state policy, to foster wise and efficient energy use and to promote energy self-sufficiency through the use of indigenous and renewable energy sources, consistent with the promotion of reliable energy sources, the general welfare, and the protection of environmental quality.

[1975-'76 2nd ex.s. c 108 § 1.]

NOTES:

Severability -- 1975-'76 2nd ex.s. c 108: "If any provision of this 1976 amendatory act, or its application to any person or circumstance is held invalid, the remainder of the act, or the application of the provision to other persons or circumstances is not affected." [1975-'76 2nd ex.s. c 108 § 45.]

Effective date -- 1975-'76 2nd ex.s. c 108: "This 1976 amendatory act is necessary for the immediate preservation of the public peace, health, and safety, the support of the state government and its existing public institutions, and shall take effect March 15, 1976." [1975-'76 2nd ex.s. c 108 § 46.]

RCW 43.21F.015
State policy.

It is the policy of the state of Washington that:

(1) The development and use of a diverse array of energy resources with emphasis on renewable energy resources shall be encouraged;

(2) The supply of energy shall be sufficient to insure the health and economic welfare of its citizens;

(3) The development and use of energy resources shall be consistent with the statutory environmental policies of the state;

(4) Energy conservation and elimination of wasteful and uneconomic uses of energy and materials shall be encouraged, and this conservation should include, but is not limited to, resource recovery and materials recycling;

(5) In energy emergency shortage situations, energy requirements to maintain the public health, safety, and welfare shall be given priority in the allocation of energy resources, and citizens and industry shall be assisted in adjusting to the limited availability of energy in order to minimize adverse impacts on their physical, social, and economic well being;

(6) State government shall provide a source of impartial and objective information in order that this energy policy may be enhanced; and

(7) The state energy strategy shall provide primary guidance for implementation of the state's energy policy.

[1994 c 207 § 3; 1981 c 295 § 1.]

NOTES:

Finding -- 1994 c 207: See note following RCW 43.21F.025.

RCW 43.21F.025
Definitions.

(1) "Energy" means petroleum or other liquid fuels; natural or synthetic fuel gas; solid carbonaceous fuels; fissionable nuclear material; electricity; solar radiation; geothermal resources; hydropower; organic waste products; wind; tidal activity; any other substance or process used to produce heat, light, or motion; or the savings from nongeneration technologies, including conservation or improved efficiency in the usage of any of the sources described in this subsection;

(2) "Person" means an individual, partnership, joint venture, private or public corporation, association, firm, public service company, political subdivision, municipal corporation, government agency, public utility district, joint operating agency, or any other entity, public or private, however organized;

(3) "Director" means the director of the department of community, trade, and economic development;

(4) "Assistant director" means the assistant director of the department of community, trade, and economic development responsible for energy policy activities;

(5) "Department" means the department of community, trade, and economic development;

(6) "Distributor" means any person, private corporation, partnership, individual proprietorship, utility, including investor-owned utilities, municipal utility, public utility district, joint operating agency, or cooperative, which engages in or is authorized to engage in the activity of generating, transmitting, or distributing energy in this state; and

(7) "State energy strategy" means the document and energy policy direction developed under section 1, chapter 201, Laws of 1991 including any related appendices.

[1996 c 186 § 102; 1994 c 207 § 2; 1987 c 330 § 501; 1981 c 295 § 2.]

NOTES:

Findings -- Intent -- Part headings not law -- Effective date -- 1996 c 186: See notes following RCW 43.330.904.

Finding -- 1994 c 207: "The legislature finds that the state energy strategy presented to the legislature in 1993 was developed by a dedicated and talented committee of hard-working representatives of the industries and people of this state and that the strategy document should serve to guide energy-related policy decisions by the legislature and other entities within this region." [1994 c 207 § 1.]

Construction -- Application of rules -- Severability -- 1987 c 330:

See notes following RCW 28B.12.050.

RCW 43.21F.045
Duties of department -- Transfer of powers and duties relating to energy education, applied research, technology transfer, and energy efficiency in public buildings.

(1) The department shall supervise and administer energy-related activities as specified in RCW 43.330.904 and shall advise the governor and the legislature with respect to energy matters affecting the state.

(2) In addition to other powers and duties granted to the department, the department shall have the following powers and duties:

   (a) Prepare and update contingency plans for implementation in the event of energy shortages or emergencies. The plans shall conform to chapter 43.21G RCW and shall include procedures for determining when these shortages or emergencies exist, the state officers and agencies to participate in the determination, and actions to be taken by various agencies and officers of state government in order to reduce hardship and maintain the general welfare during these emergencies. The department shall coordinate the activities undertaken pursuant to this subsection with other persons. The components of plans that require legislation for their implementation shall be presented to the legislature in the form of proposed legislation at the earliest practicable date. The department shall report to the governor and the legislature on probable, imminent, and existing energy shortages, and shall administer energy allocation and curtailment programs in accordance with chapter 43.21G RCW.

(b) Establish and maintain a central repository in state government for collection of existing data on energy resources, including:

(i) Supply, demand, costs, utilization technology, projections, and forecasts;

(ii) Comparative costs of alternative energy sources, uses, and applications; and

(iii) Inventory data on energy research projects in the state conducted under public and/or private auspices, and the results thereof.

(c) Coordinate federal energy programs appropriate for state-level implementation, carry out such energy programs as are assigned to it by the governor or the legislature, and monitor federally funded local energy programs as required by federal or state regulations.

(d) Develop energy policy recommendations for consideration by the governor and the legislature.

(e) Provide assistance, space, and other support as may be necessary for the activities of the state's two representatives to the Pacific northwest electric power and conservation planning council. To the extent consistent with federal law, the director shall request that Washington's council members request the administrator of the Bonneville power administration to reimburse the state for the expenses associated with the support as provided in the Pacific Northwest Electric Power Planning and Conservation Act (P.L. 96-501).

(f) Cooperate with state agencies, other governmental units, and private interests in the prioritization and implementation of the state energy strategy elements and on other energy matters.

(g) Serve as the official state agency responsible for coordinating implementation of the state energy strategy.

(h) No later than December 1, 1982, and by December 1st of each even-numbered year thereafter, prepare and transmit to the governor and the appropriate committees of the legislature a report on the implementation of the state energy strategy and other important energy issues, as appropriate.

(i) Provide support for increasing cost-effective energy conservation, including assisting in the removal of impediments to timely implementation.

(j) Provide support for the development of cost-effective energy resources including assisting in the removal of impediments to timely construction.

(k) Adopt rules, under chapter 34.05 RCW, necessary to carry out the powers and duties enumerated in this chapter.

(l) Provide administrative assistance, space, and other support as may be necessary for the activities of the energy facility site evaluation council, as provided for in RCW 80.50.030.

(m) Appoint staff as may be needed to administer energy policy functions and manage energy facility site evaluation council activities. These employees are exempt from the provisions of chapter 41.06 RCW.

(3) To the extent the powers and duties set out under this section relate to energy education, applied research, and technology transfer programs they are transferred to Washington State University.

(4) To the extent the powers and duties set out under this section relate to energy efficiency in public buildings they are transferred to the department of general administration.

[1996 c 186 § 103; 1994 c 207 § 4; 1990 c 12 § 2; 1987 c 505 § 29; 1981 c 295 § 4.]

NOTES:

Findings -- Intent -- Part headings not law -- Effective date -- 1996 c 186: See notes following RCW 43.330.904.

Finding -- 1994 c 207: See note following RCW 43.21F.025.

Effective date -- 1990 c 12: See note following RCW 80.50.030.

RCW 43.21F.055
Intervention in certain regulatory proceedings prohibited -- Application to energy facility site evaluation council -- Avoidance of duplication of activity.

The department shall not intervene in any regulatory proceeding before the Washington utilities and transportation commission or proceedings of utilities not regulated by the commission. Nothing in this chapter abrogates or diminishes the functions, powers, or duties of the energy facility site evaluation council pursuant to chapter 80.50 RCW, the utilities and transportation commission pursuant to Title 80 RCW, or other state or local agencies established by law.

The department shall avoid duplication of activity with other state agencies and officers and other persons.

[1996 c 186 § 104; 1981 c 295 § 5.]

NOTES:

Findings -- Intent -- Part headings not law -- Effective date -- 1996 c 186: See notes following RCW 43.330.904.

RCW 43.21F.060
Additional duties and authority of department -- Obtaining information -- Confidentiality, penalty -- Receiving and expending funds.

In addition to the duties prescribed in RCW 43.21F.045, the department shall have the authority to:

(1) Obtain all necessary and existing information from energy producers, suppliers, and consumers, doing business within the state of Washington, from political subdivisions in this state, or any person as may be necessary to carry out the provisions of chapter 43.21G RCW:

PROVIDED, That if the information is available in reports made to another state agency, the department shall obtain it from that agency: PROVIDED FURTHER, That, to the maximum extent practicable, informational requests to energy companies regulated by the utilities and transportation commission shall be channeled through the commission and shall be accepted in the format normally used by the companies. Such information may include but not be limited to:

(a) Sales volume;

(b) Forecasts of energy requirements; and

(c) Energy costs.

Notwithstanding any other provision of law to the contrary, information furnished under this subsection shall be confidential and maintained as such, if so requested by the person providing the information, if the information is proprietary.

It shall be unlawful to disclose such information except as hereinafter provided. A violation shall be punishable, upon conviction, by a fine of not more than one thousand dollars for each offense. In addition, any person who wilfully or with criminal negligence, as defined in RCW 9A.08.010, discloses confidential information in violation of this subsection may be subject to removal from office or immediate dismissal from public employment notwithstanding any other provision of law to the contrary.

Nothing in this subsection prohibits the use of confidential information to prepare statistics or other general data for publication when it is so presented as to prevent identification of particular persons or sources of confidential information.

(2) Receive and expend funds obtained from the federal government or other sources by means of contracts, grants, awards, payments for services, and other devices in support of the duties enumerated in this chapter.

[1996 c 186 § 105; 1981 c 295 § 6; 1975-'76 2nd ex.s. c 108 § 6.]

NOTES:

Findings -- Intent -- Part headings not law -- Effective date -- 1996 c 186: See notes following RCW 43.330.904.

RCW 43.21F.090
State energy strategy -- Review and report to legislature.

The department shall review the state energy strategy as developed under section 1, chapter 201, Laws of 1991, periodically with the guidance of an advisory committee.

For each review, an advisory committee shall be established with a membership resembling as closely as possible the original energy strategy advisory committee specified under section 1, chapter 201, Laws of 1991. Upon completion of a public hearing regarding the advisory committee's advice and recommendations for revisions to the energy strategy, a written report shall be conveyed by the department to the governor and the appropriate legislative committees. Any advisory committee established under this section shall be dissolved within three months after their written report is conveyed.

[1996 c 186 § 106; 1994 c 207 § 5.]

NOTES:

Findings -- Intent -- Part headings not law -- Effective date -- 1996 c 186: See notes following RCW 43.330.904.

Finding -- 1994 c 207: See note following RCW 43.21F.025.

[43.21F.400 Western Interstate Nuclear Compact Not Included]

RCW 43.21G ENERGY SUPPLY EMERGENCIES, ALERTS APPENDIX B

RCW 43.21G.010
Legislative finding -- Intent.

The legislature finds that energy in various forms is increasingly subject to possible shortages and supply disruptions, to the point that there may be foreseen an emergency situation, and that without the ability to institute appropriate emergency measures to regulate the production, distribution, and use of energy, a severe impact on the public health, safety, and general welfare of our state's citizens may occur. The prevention or mitigation of such energy shortages or disruptions and their effects is necessary for preservation of the public health, safety, and general welfare of the citizens of this state.

It is the intent of this chapter to:

(1) Establish necessary emergency powers for the governor and define the situations under which such powers are to be exercised;

(2) Provide penalties for violations of this chapter.

It is further the intent of the legislature that in developing proposed orders under the powers granted in RCW 43.21G.040 as now or hereafter amended the governor may utilize, on a temporary or ad hoc basis, the knowledge and expertise of persons experienced in the technical aspects of energy supply, distribution, or use. Such utilization shall be in addition to support received by the governor from the department of community, trade, and economic development under RCW 43.21F.045 and *43.21F.065 and from other state agencies.

[1996 c 186 § 507; 1981 c 295 § 11; 1977 ex.s. c 328 § 1; 1975-'76 2nd ex.s. c 108 § 15.]

NOTES:

*Reviser's note: RCW 43.21F.065 was repealed by 1996 c 186 § 524, effective July 1, 1996.

Findings -- Intent -- Part headings not law -- Effective date -- 1996 c 186: See notes following RCW 43.330.904.

Severability -- 1977 ex.s. c 328: "If any provision of this 1977 amendatory act, or its application to any person or circumstance is held invalid, the remainder of the act, or the application of the provision to other persons or circumstances is not affected." [1977 ex.s. c 328 § 20.]

RCW 43.21G.020
Definitions.

As used in this chapter:

(1) "Energy supply facility" means a facility which produces, extracts, converts, transports, or stores energy.

(2) "Energy" means any of the following, individually or in combination: Petroleum fuels; other liquid fuels; natural or synthetic fuel gas; solid carbonaceous fuels; fissionable nuclear material, or electricity.

(3) "Person" means an individual, partnership, joint venture, private or public corporation, association, firm, public service company, political subdivision, municipal corporation, government agency, public utility district, joint operating agency or any other entity, public or private, however organized.

(4) "Committee" means the joint committee on energy and utilities created by RCW 44.39.010 as now or hereafter amended.

(5) "Distributor" means any person, private corporation, partnership, individual proprietorship, utility, including investor-owned utilities, joint operating agencies, municipal utility, public utility district, or cooperative, which engages in or is authorized to engage in the activity of generating, transmitting, or distributing energy in this state.

(6) "Regulated distributor" means a public service company as defined in chapter 80.04 RCW which engages in or is authorized to engage in the activity of generating, transmitting, or distributing energy in this state.

(7) "Energy supply alert" means a situation which threatens to disrupt or diminish the supply of energy to the extent that the public health, safety, and general welfare may be jeopardized.

(8) "Energy emergency" means a situation in which the unavailability or disruption of the supply of energy poses a clear and foreseeable danger to the public health, safety, and general welfare.

(9) "State or local governmental agency" means any county, city, town, municipal corporation, political subdivision of the state, or state agency.

[1977 ex.s. c 328 § 2; 1975-'76 2nd ex.s. c 108 § 16.]

NOTES:

Severability -- 1977 ex.s. c 328: See note following RCW 43.21G.010.

RCW 43.21G.030
Intent in developing energy production, allocation, and consumption programs.

It is the intent of the legislature that the governor shall, in developing plans for the production, allocation, and consumption of energy, give high priority to supplying vital public services including, but not limited to, essential governmental operations, public health and safety functions, emergency services, public mass transportation systems, fish production, food production and processing facilities, including the provision of water to irrigated agriculture, and energy supply facilities, during a condition of energy supply alert or energy emergency. In developing any such plans, provisions should be made for the equitable distribution of energy among the geographic areas of the state.

It is further the intent of the legislature that the governor shall, to the extent possible, encourage and rely upon voluntary programs and local and regional programs for the production, allocation, and consumption of energy and that involvement of energy users and producers be secured in implementing such programs.

[1977 ex.s. c 328 § 3; 1975-'76 2nd ex.s. c 108 § 17.]

NOTES:

Severability -- 1977 ex.s. c 328: See note following RCW 43.21G.010.

RCW 43.21G.040
Governor's energy emergency powers -- Energy supply alert -- Construction of chapter.

(1) The governor may subject to the definitions and limitations provided in this chapter:

(a) Upon finding that an energy supply alert exists within this state or any part thereof, declare a condition of energy supply alert; or

(b) Upon finding that an energy emergency exists within this state or any part thereof, declare a condition of energy emergency. A condition of energy emergency shall terminate thirty consecutive days after the declaration of such condition if the legislature is not in session at the time of such declaration and if the governor fails to convene the legislature pursuant to Article III, section 7 of the Constitution of the state of Washington within thirty consecutive days of such declaration. If the legislature is in session or convened, in accordance with this subsection, the duration of the condition of energy emergency shall be limited in accordance with subsection (3) of this section.

Upon the declaration of a condition of energy supply alert or energy emergency, the governor shall present to the committee any proposed plans for programs, controls, standards, and priorities for the production, allocation, and consumption of energy during any current or anticipated condition of energy emergency, any proposed plans for the suspension or modification of existing rules of the Washington Administrative Code, and any other relevant matters the governor deems desirable. The governor shall review any recommendations of the committee concerning such plans and matters.

Upon the declaration of a condition of energy supply alert or energy emergency, the emergency powers as set forth in this chapter shall become effective only within the area described in the declaration.

(2) A condition of energy supply alert shall terminate ninety consecutive days after the declaration of such condition unless:

(a) Extended by the governor upon issuing a finding that the energy supply alert continues to exist, and with prior approval of such an extension by the committee; or

(b) Extended by the governor based on a declaration by the president of the United States of a national state of emergency in regard to energy supply; or

(c) Upon the request of the governor, extended by declaration of the legislature by concurrent resolution of a continuing energy supply alert.

In the event any such initial extension is implemented, the condition shall terminate one hundred and fifty consecutive days after the declaration of such condition. One or more subsequent extensions may be implemented through the extension procedures set forth in this subsection. In the event any such subsequent extension is implemented, the condition shall terminate sixty consecutive days after the implementation of such extension.

(3) A condition of energy emergency shall terminate forty-five consecutive days after the declaration of such condition unless:

(a) Extended by the governor upon issuing a finding that the energy emergency continues to exist, and with prior approval of such an extension by the committee; or

(b) Extended by the governor based on a declaration by the president of the United States of a national state of emergency in regard to energy supply; or

(c) Upon the request of the governor, extended by declaration of the legislature by concurrent resolution of a continuing energy emergency.

In the event any such initial extension is implemented, the condition shall terminate ninety consecutive days after the declaration of such condition. One or more subsequent extensions may be implemented through the extension procedures set forth in this subsection. In the event any such subsequent extension is implemented, the condition shall terminate forty-five consecutive days after the implementation of such extension.

(4) A condition of energy supply alert or energy emergency shall cease to exist upon a declaration to that effect by either of the following: (a) The governor; or (b) the legislature, by concurrent resolution, if in regular or special session: PROVIDED, That the governor shall terminate a condition of energy supply alert or energy emergency when the energy supply situation upon which the declaration of a condition of energy supply alert or energy emergency was based no longer exists.

(5) In a condition of energy supply alert, the governor may, as deemed necessary to preserve and protect the public health, safety, and general welfare, and to minimize, to the fullest extent possible, the injurious economic, social, and environmental consequences of such energy supply alert, issue orders to: (a) Suspend or modify existing rules of the Washington Administrative Code of any state agency relating to the consumption of energy by such agency or to the production of energy, and (b) direct any state or local governmental agency to implement programs relating to the consumption of energy by the agency which have been developed by the governor or the agency and reviewed by the committee.

(6) In addition to the powers in subsection (5) of this section, in a condition of energy emergency, the governor may, as deemed necessary to preserve and protect the public health, safety, and general welfare, and to minimize, to the fullest extent possible, the injurious economic, social, and environmental consequences of such an emergency, issue orders to: (a) Implement programs, controls, standards, and priorities for the production, allocation, and consumption of energy; (b) suspend and modify existing pollution control standards and requirements or any other standards or requirements affecting or affected by the use of energy, including those relating to air or water quality control; and (c) establish and implement regional programs and agreements for the purposes of coordinating the energy programs and actions of the state with those of the federal government and of other states and localities.

The governor shall immediately transmit the declaration of a condition of energy supply alert or energy emergency and the findings upon which the declaration is based and any orders issued under the powers granted in this chapter to the committee.

Nothing in this chapter shall be construed to mean that any program, control, standard, priority or other policy created under the authority of the emergency powers authorized by this chapter shall have any continuing legal effect after the cessation of the condition of energy supply alert or energy emergency.

If any provision of this chapter is in conflict with any other provision, limitation, or restriction which is now in effect under any other law of this state, including, but not limited to, chapter 34.05 RCW, this chapter shall govern and control, and such other law or rule or regulation promulgated thereunder shall be deemed superseded for the purposes of this chapter.

Because of the emergency nature of this chapter, all actions authorized or required hereunder, or taken pursuant to any order issued by the governor, shall be exempted from any and all requirements and provisions of the state environmental policy act of 1971, chapter 43.21C RCW, including, but not limited to, the requirement for environmental impact statements.

Except as provided in this section nothing in this chapter shall exempt a person from compliance with the provisions of any other law, rule, or directive unless specifically ordered by the governor.

[1987 c 505 § 83; 1985 c 308 § 1; 1981 c 281 § 1; 1980 c 87 § 23; 1979 ex.s. c 158 § 1;
1977 ex.s. c 328 § 4; 1975-'76 2nd ex.s. c 108 § 18.]

NOTES:

Effective date -- 1985 c 308: "This act is necessary for the immediate preservation of the public peace, health, and safety, the support of the state government and its existing public institutions, and shall take effect June 29, 1985." [1985 c 308 § 2.]

Severability -- 1981 c 281: "If any provision of this act or its application to any person or circumstance is held invalid, the remainder of the act or the application of the provision to other persons or circumstances is not affected." [1981 c 281 § 3.]
Severability -- 1977 ex.s. c 328: See note following RCW 43.21G.010.

RCW 43.21G.050
Duty of executive authority of state and local governmental agencies to carry out supply alert or emergency measures -- Liability for actions.

To protect the public welfare during a condition of energy supply alert or energy emergency, the executive authority of each state or local governmental agency is hereby authorized and directed to take action to carry out the orders issued by the governor pursuant to this chapter as now or hereafter amended. A local governmental agency shall not be liable for any lawful actions consistent with RCW 43.21G.030 as now or hereafter amended taken in good faith in accordance with such orders issued by the governor.

[1981 c 281 § 2; 1977 ex.s. c 328 § 5; 1975-'76 2nd ex.s. c 108 § 19.]

NOTES:

Severability -- 1981 c 281: See note following RCW 43.21G.040.

Severability -- 1977 ex.s. c 328: See note following RCW 43.21G.010.

RCW 43.21G.060
Consideration of actions, orders, etc., of federal authorities.

In order to attain uniformity, as far as is practicable throughout the United States, in measures taken to aid in energy crisis management, all action taken under this chapter as now or hereafter amended, and all orders and rules made pursuant hereto, shall be taken or made with due consideration for and consistent when practicable with the orders, rules, regulations, actions, recommendations, and requests of federal authorities.

[1977 ex.s. c 328 § 6; 1975-'76 2nd ex.s. c 108 § 20.]

NOTES:

Severability -- 1977 ex.s. c 328: See note following RCW 43.21G.010.

RCW 43.21G.070
Compliance by affected persons.

Notwithstanding any provision of law or contract to the contrary, all persons who are affected by an order issued or action taken pursuant to this chapter as now or hereafter amended shall comply therewith immediately.

[1977 ex.s. c 328 § 7; 1975-'76 2nd ex.s. c 108 § 21.]

NOTES:

Severability -- 1977 ex.s. c 328: See note following RCW 43.21G.010.

RCW 43.21G.080
Compliance by distributors -- Fair and just reimbursement.

The governor may order any distributor to take such action on his behalf as may be required to implement orders issued pursuant to this chapter as now or hereafter amended: PROVIDED, That orders to regulated distributors shall be issued by the Washington utilities and transportation commission in conformance with orders of the governor. No distributor shall be liable for actions taken in accordance with such orders issued by the governor or the Washington utilities and transportation commission.

All allocations of energy from one distributor to another distributor pursuant to orders issued or as a result of actions taken under this chapter as now or hereafter amended are subject to fair and just reimbursement. Such reimbursement for any allocation of energy between regulated distributors shall be subject to the approval of the Washington utilities and transportation commission. A distributor is authorized to enter into agreements with another distributor for the purpose of determining financial or commodity reimbursement.

[1977 ex.s. c 328 § 8; 1975-'76 2nd ex.s. c 108 § 22.]

NOTES:

Severability -- 1977 ex.s. c 328: See note following RCW 43.21G.010.

RCW 43.21G.090
Petition for exception or modification -- Appeals.

(1) Any person aggrieved by an order issued or action taken pursuant to this chapter as now or hereafter amended may petition the governor and request an exception from or modification of such order or action. The governor may grant, modify, or deny such petition as the public interest may require.

(2) An appeal from any order issued or action taken pursuant to this chapter as now or hereafter amended may be taken to the state supreme court. Such an appeal shall take the form of a petition for a writ of mandamus or prohibition under Article IV, section 4 of the state Constitution, and the supreme court shall have exclusive jurisdiction to hear and act upon such an appeal. Notwithstanding the provisions of chapter 7.16 RCW, or any other applicable statute, the superior courts of this state shall have no jurisdiction to entertain an action or suit relating to any order issued or action taken pursuant to this chapter as now or hereafter amended, nor to hear and determine any appeal from any such order.

The provisions of Rule 16.2, Rules of Appellate Procedure, shall apply to any proceedings in the supreme court brought pursuant to this chapter as now or hereafter amended.

[1977 ex.s. c 328 § 9; 1975-'76 2nd ex.s. c 108 § 23.]

NOTES:

Severability -- 1977 ex.s. c 328: See note following RCW 43.21G.010.

RCW 43.21G.100
Penalty.

Any person wilfully violating any provision of an order issued by the governor pursuant to this chapter shall be guilty of a gross misdemeanor.
[1975-'76 2nd ex.s. c 108 § 24.]

RCW 43.21G.900
Severability -- Effective date -- 1975-'76 2nd ex.s. c 108.

See notes following RCW 43.21F.010.

List of Acronyms and Abbreviations

aMW	Average Megawatt (8,760 MW-hours)
ATC	Available transfer capability
Bi-Op	Biological Opinion
BPA	Bonneville Power Administration
CRAC	Cost Recovery Adjustment Clause
CREPC	Committee for Regional Electric Power Cooperation
CTED	Washington State Department of Community, Trade and Economic Development
EFSEC	Energy Facility Site Evaluation Council
EIA	Energy Information Administration
ERT	Emergency Response Team
FCRPS	Federal Columbia River Power System
FERC	Federal Energy Regulatory Commission
FTR	Firm Transmission Right
kWh	Kilowatt hour
ICLEI	International Council for Local Environmental Initiatives
IOU	Investor-owned utility
IPCC	Intergovernmental Panel of Climate Change
IPP	Independent power producer
ISO	Independent System Operator
JISAO	Joint Institute for the Study of Atmosphere and Ocean
LED	Light-emitting diode
MMBtu	Million Btu
MW	Megawatt
NAERO	North American Electricity Reliability Organization
NERC	North American Electric Reliability Council
NOPR	Notice of proposed rulemaking
NRTA	Northwest Regional Transmission Association
NWPP	Northwest Power Pool
NWPPC	Northwest Power Planning Council
OPEC	Organization of Petroleum Exporting Countries
OTED	Washington State Office of Trade and Economic Development
PSC	Public Service Commission

PX	Power Exchange
RRG	Regional Representatives Group
RRO	Regional Reliability Organization
RTA	Regional Transmission Association
RTF	Regional Technical Forum
RTO	Regional Transmission Organization
SBC	Systems Benefit Charge
SEDS	State Energy Data System (EIA)
SRRO	Self-regulating Reliability Organization
SWRTA	Southwest Regional Transmission Association
WICF	Western Interconnection Forum
WIO	Western Interconnection Organization
WRTA	Western Regional Transmission Association
WSCC	Western Systems Coordinating Council